

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 5 77 WEST JACKSON BOULEVARD CHICAGO, IL 60604-3590

JUN 2 7 2013

REPLY TO THE ATTENTION OF:

Tony Sullins, Field Supervisor Twin Cities Minnesota Field Office United States Fish and Wildlife Service 4101 East 80th Street Bloomington, Minnesota 55425-1665

Dear Mr. Sullins:

Pursuant to Section 7 of the Endangered Species Act, (87 Stat. 884, as amended; 16 U.S. C. 1531 et seq.), the U. S. Environmental Protection Agency has reviewed the biological information and analysis related to a Prevention of Significant Deterioration permit for a proposed project by Flint Hills Resources (Flint Hills), Rosemount, Minnesota facility to determine what impact there may be to any threatened or endangered species. The purpose of this letter is to seek concurrence from the U. S. Fish and Wildlife Service on our determination that the proposed project may affect but is not likely to adversely affect any federally listed species in relation to the proposed air quality permit for this facility.

Flint Hills is planning a #3crude/coker improvement project that includes two separate projects and a sulfur dioxide emissions reduction project. Flint Hills provided a complete analysis of impacts from the proposed expansion on May 17, 2013. The analysis was prepared by Barr Engineering. EPA finds that the analysis performed by Barr Engineering provides a conservative estimate of impacts from the expansion, and that the actual impact for the project will likely be less than predicted. The additional impact to threatened or endangered species from the expansion is insignificant with respect to background and selected benchmarks. Based on the information submitted, EPA finds that the proposed project may affect, but is not likely to adversely affect any endangered or threatened species.

If you have any questions with respect to this letter, please contact Jennifer Darrow, of my staff, at (312) 886-6315.

Sincerely,

Genevieve Damico

Chief

Air Permits Section

cc: Tarik Hanafy, MPCA



Pine Bend Refinery

ENVIRONMENTAL DEPARTMENT

P.O. Box 64596 Saint Paul, Minnesota 55164-0596 651.437.0700

January 25, 2013

Ms. Jennifer Darrow US EPA Region 5 77 West Jackson Boulevard Mail Code: AR-18J Chicago, IL 60604-3507

RE:

Flint Hills Resources Pine Bend, LLC

Endangered Species Act Biological Evaluation in Support of the #3 Crude/Coker

Improvements Permit Application

Dear Ms. Darrow:

Please find the attached report providing Flint Hills Resources Pine Bend Refinery's Endangered Species Act Biological Evaluation in support of the #3 Crude/Coker Improvements PSD Permit Application submitted to the Minnesota Pollution Control Agency (MPCA) on November 16, 2012. This information is provided for your use in initiating an informal consultation with the U.S. Fish and Wildlife Service (USFWS) per the requirements of Section 7 of the Endangered Species Act.

The PSD permit review is currently underway at the MPCA. We anticipate that MPCA will prefer to have the informal consultation completed and USFWS concurrence on the ESA results prior to July 2013, which is the estimated timeframe that the public comment period will begin. Construction for the projects is scheduled to begin starting in November 2013 in order to accommodate process unit shut down and turnaround windows starting in February 2014.

If you have any questions about this submittal, please contact me at <u>michael.sinclair@fhr.com</u> (651) 437-0625, or Sue Anderson at <u>sue anderson@fhr.com</u> or (651) 438-1214.

Sincerely,

Mike Sinclair

Senior Air Permitting Engineer

Flint Hills Resources Pine Bend Refinery

Encl.

cc: Mr. Tony Sullins, Field Supervisor, USFWS

Mr. Tarik Hanafy, MPCA

Endangered Species Act Biological Evaluation

Flint Hills Resources Pine Bend, LLC Rosemount, Minnesota

In Support of #3 Crude/Coker Improvements Permit Application

Prepared for Flint Hills Resources

January 2013

Endangered Species Act Biological Evaluation

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Endangered Species Act Biological Evaluation

Flint Hills Resources Pine Bend, LLC Rosemount, Minnesota

In Support of #3 Crude/Coker Improvements Permit Application

January 2013

Table of Contents

1.0 Execu	ıtive Suı	nmary	1
1.1	Existir	ng Site Description	1
1.2	Projec	t Description	1
1.3	Identif	ication of the Action Area	3
1.4	Federa	lly Listed Threatened and Endangered Species	6
1.5	Conclu	usions	6
2.0 Introd		and Project Description.	
2.1	Reason	n for the Section 7 ESA Consultation	7
2.2		t Description	
	2.2.1	Estimated Air Emissions from the Projects	10
	2.2.2	Detailed Description of the #3 Crude Unit Improvements Project	13
	2.2.3	Detailed Description #3 Coker Unit Improvements Project	17
	2.2.4	Detailed Description of #3 Coker Fuel Gas Sulfur Reductions Project	20
3.0 ESA	Methodo	ology and Scope	22
3.1	Study	Area and Action Area	22
3.2	Step O	ne: Identify the Study Area	22
3.3		wo: Identify the Action Area of Potential Direct Effects	
	3.3.1	Ground Disturbance and Construction Activities	23
	3.3.2	Noise	24
	3.3.3	Lighting and Visible Impacts	24
	3.3.4	Intrusion into Air Space (Height of Structures)	24
	3.3.5	Water Intake and Discharge	24
3.4	Step T	hree: Identify the Area of Potential Indirect Effects	25
	3.4.1	De Minimis Emission Rates.	
	3.4.2	Emission Changes	
	3.4.3	Modeled Criteria Pollutant Air Concentrations	27
	3.4.4	Qualitative Assessment of Hazardous Air Pollutants	27

	3.4.4.1 Particulate Metals	27
	3.4.4.2 Volatile Organic Compounds (VOCs)	29
	3.4.5 Emissions of Nitrogen (NO _X and Ammonia) and Potential Effects to Soil and Vegetation	29
	3.4.6 Emissions of Sulfur (SO ₂ , SAM, H ₂ S and RSC) and Potential Effects to Soil and Vegetation	32
	3.4.7 Qualitative Assessment of Potential Effects from Wastewater Discharge	32
3.5	Step 4. Define the Action Area	32
4.0 Desc	ription of Federally Listed Species	
4.1	Higgins-eye Pearly Mussel	34
4.2	Winged Mapleleaf Mussel	
4.3	Prairie Bush Clover	37
5.0 Effec	ets of the Permitting Action	39
5.1	Air Quality	39
5.2	Water Quantity and Water Quality	
5.3	Noise	
5.4	Infrastructure-Related Impacts	40
5.5	Human Activity Impacts	40
5.6	Species Effect Analysis	41
6.0 Conc	clusion	
7.0 Refe	rences	43

Attachment 1 - ESA Emission Calculation Table

List of Tables

Table 1	Summary of PSD Regulated Pollutants Evaluated for Potential Effects to Federal-Listed Threatened and Endangered Species
Table 2.	Estimated PSD Emission Increases for the #3 Crude/Coker Improvements Permit 12
Table 3.	Actual Emissions Changes Associated with the #3 Crude/Coker Improvements Projects and Comparison to Facility PTE
Table 4.	Estimated Emissions of Particulate Metals Associated with the #3 Crude/Coker Improvements Permit and Comparison to Screening Emission Rates
Table 5.	Estimated Deposition of Nitrogen from Potential Ammonia Emissions Associated with the #3 Crude/Coker Improvements Permit*
	List of Figures
Figure 1	Approximate location of the Flint Hills Resources Pine Bend, LLC Refinery in Rosemont, Dakota County, Minnesota (Source: FHR Pine Bend, LLC)
Figure 2.	Process Flow Diagram of the Relationship Between the #2 Crude Atmospheric Unit and the #3 Crude Vacuum Unit at the Flint Hills Resources Pine Bend, LLC Refinery in Rosemont, Dakota County, Minnesota
Figure 3.	Process Flow Diagram for Delayed Coking Unit 23
Figure 4	Extent of Potential Habitat for the Winged Mapleleaf Mussel and its Known Occurrence in the St. Croix River near Taylors Falls, Minnesota
Figure 5.	Land Cover and Land Use Around the Flint Hills Resources Pine Bend, LLC Refinery in Rosemount, Dakota County, Minnesota

Abbreviations and Acronyms

acfm actual cubic feet per minute

BACT Best Available Control Technology

BE Biological Evaluation

CE Control Equipment

CO Carbon Monoxide

cfm cubic feet per minute

CFR Code of Federal Regulation

ESA Endangered Species Act

EU Emission Unit

HAP Hazardous Air Pollutant

 \dot{H}_2S Hydrogen sulfide

H₂SO₄ Sulfuric Acid

km kilometer

MDNR Minnesota Department of Natural Resources

MMBtu/hr One million British thermal units per hour

MPCA Minnesota Pollution Control Agency

NAAQS National Ambient Air Quality Standard

NAD 83 North American Datum (1983)

NO_X Nitrogen Oxides

PM/PM₁₀ Particulate Matter / Particulate Matter less than 10 microns in size

PSD Prevention of Significant Deterioration (air permitting)

PTE Potential to Emit

Region 5 USEPA; encompasses Michigan, Wisconsin, Minnesota, Ohio, Indiana, Illinois

SO₂ Sulfur dioxide

SIL Significant Impact Level for Class II areas; for PM₁₀, the SIL is one μg/m³

SV Stack/Vent

USEPA U.S. Environmental Protection Agency

USFWS U.S. Fish and Wildlife Service

UTM Universal Transverse Mercator system; x and y coordinates for geographic locations

μg/m³ microgram per cubic meter

VOC Volatile organic compound

Flint Hills Resources (FHR) is proposing modifications to its Pine Bend Refinery located in Rosemount, Dakota County, Minnesota (Figure 1). The proposed modifications require an air permit under the Prevention of Significant Deterioration (PSD) program pursuant to the federal Clean Air Act (CAA). The Minnesota Pollution Control Agency (MPCA) has been delegated authority by the U.S. Environmental Protection Agency (USEPA) to issue PSD permits under the federal PSD regulations set forth at 40 C.F.R. Part 52. The action by MPCA of issuing a federal PSD permit under its delegated authority qualifies as an "agency action" that triggers the consultation requirements of the Endangered Species Act, 16 U.S.C. § 1531, et seq. (ESA). This Biological Evaluation (BE) provides the information necessary to support USEPA's obligations under ESA Section 7.

1.1 Existing Site Description

FHR operates the Pine Bend Refinery located in Rosemont, Dakota County, Minnesota. The Pine Bend Refinery is a major supplier of transportation fuels and energy products to Minnesota and the Upper Midwest. The Pine Bend Refinery currently has a crude oil processing capacity of about 320,000 barrels per day.

1.2 Project Description

This #3 Crude/Coker Improvements permit action covers two separate projects and a separate emissions reduction project involving changes to emissions units as follows:

- 1. The #3 Crude Unit Improvements Project includes upgrades to the #3 Crude Unit and provides additional cooling water capacity. This project will result in the upgrade of the #6 Cooling Tower, the construction of a new #7 Cooling Tower, or both to provide additional cooling water capacity. FHR will replace the 25 Crude Unit Charge Heater (25H1) with a new heater (new 25H2) equipped with ultra-low NO_X burners (ULNB) and selective catalytic reduction (SCR) technology and improve heater efficiency via air preheat design, all of which will result in reduced actual nitrogen oxide (NO_X) emissions. The #2 Crude Unit Charge Heater (11H6) will also be upgraded by installation of SCR technology and improved heater efficiency via air preheat design.
- 2. The #3 Coker Improvements Project includes replacement of two process heaters in the 23 Coker Unit with a single new process heater (new 23H3). The new heater will have ULNB and SCR, and will take advantage of energy efficient design. Installation of this new heater

will eliminate hydrogen sulfide (H₂S) emissions that occur during infrequent, short-term periods (approximately one day each calendar quarter) of heater decoking. Because the #3 Coker Improvements Project which installs a new 23H3 heater is a separate project from the #3 Crude Unit Improvements Project, the project may or may not proceed even if the #3 Crude Unit Improvements Project proceeds. This biological evaluation takes this optionality into account and highlights sections where not proceeding with this project increases potential impacts to be evaluated.

3. A third project is being completed to support sulfur dioxide (SO₂) emissions reductions from fired heaters affected by and included within both the #3 Crude Unit Improvements Project and #3 Coker Improvements Project. This third project will be completed if either the #3 Crude Improvements Project or the #3 Coker Improvements project are completed. Within the gas recovery system of the #3 Coker Unit, FHR proposes to complete physical changes to improve cooling and recovery of sulfur compounds that will directly reduce the sulfur content of produced refinery fuel gas that is routed to the 45 fuel gas system (one of the two fuel gas systems in the refinery). The fuel gas sulfur control project will reduce SO₂ emissions at the combined fuel gas systems (GP116 – the 41 and 45 fuel gas systems).

The collective permitted SO_2 and NO_X emissions impact of these changes—shutting down three process heaters, installing two new process heaters and upgrading a third heater with ULNB and SCR technology, implementing an emissions reduction project to reduce sulfur content in fuel gas, and accounting for emissions increases at other equipment resulting from the proposed changes—yields a decrease in SO_2 emissions and a decrease in NO_X emissions.

The #3 Crude/Coker Improvements permit is a major modification subject to PSD review for particulate matter (PM, PM₁₀, and PM_{2.5}) and for greenhouse gas (GHG) emissions. Potential air emissions associated with the combined projects indicate that particulate matter (PM, PM₁₀, and PM_{2.5}) and greenhouse gases (GHGs; CO₂e basis) related to combustion of fuel gas exceed the PSD significant emission rate (SER).

- PM: 31.3 tpy compared to SER of 25 tpy
- PM₁₀: 29.6 tpy compared to SER of 15 tpy

¹ For the purposes of NSR applicability, a netting analysis is not conducted so the PSD emission representations in the permit application do not reflect any emission reductions. The above-noted decrease in refinery emissions from the projects is calculated from the project emissions increase under NSR in conjunction with the federally enforceable emissions decreases proposed in this permit action from shutdown units and proposed emissions controls at existing project-affected units.

- PM_{2.5}: 28.0 tpy compared to SER of 10 tpy
- GHGs (CO₂-equivalent basis): 419,553 tpy compared to SER of 75,000 tpy

The PSD Permit Application provides additional details on these emission increases.

The permit will result in decreases in actual emissions of NO_X and SO_2 . The permit terms include a requirement to shut down three existing heaters which result in NO_X emission reductions that are greater than the projected NO_X emissions increases for the permit. While FHR does not utilize these reductions for NSR netting purposes (the increases from the projects alone are less than the NSR significant emission rate), the proposed enforceable requirements to shut down these heaters assures from an impact assessment perspective that the permit will not result in actual emission increases of NO_X .

The fuel gas sulfur control project will reduce sulfur dioxide emissions from firing of fuel gas used in refinery heaters. A proposed permit term requires reductions in the refinery fuel gas SO₂ emissions that more than offset the projected SO₂ increases. As with NO_x, FHR is not performing NSR netting; however, the proposed enforceable requirement that reduces refinery fuel gas SO₂ emissions assures from an impact assessment perspective that the permit will not result in actual emissions increases of SO₂.

Other potential increases in emissions associated with the combined projects include VOCs (34.7 tpy; PSD SER is 40 tpy) and ammonia (20.1 tpy; no PSD SER). Estimated VOC emissions are associated with fuel gas combustion, cooling towers, and from equipment in VOC service. Estimated ammonia emissions are associated with the use of selective catalytic reduction (SCR) to control NO_X emissions related to fuel gas combustion. Emission increases for VOCs and ammonia are assessed further in Section 3.4.

1.3 Identification of the Action Area

The "action area" bounds the scope of the analysis of effects of the action, (USFWS 1998 at 4-15), and so defining the "action area" is the first step in the Section 7 effects analysis process. USFWS regulations define an "action area" as "all areas to be affected directly or indirectly by the Federal action and not merely the immediate area involved in the action." (50 C.F.R. § 402.02) "Direct effects" are defined as those "direct or immediate effects of the project on the species or its habitat," (USFWS 1998 at 4-26). "Indirect effects" are defined as those effects that "are caused by or result from the proposed action, are later in time, and are reasonably certain to occur." (*Id.* at 4-29) Further,

"[i]ndirect effects may occur outside of the area directly affected by the action." (*Id.*) FHR identified the Action Area for the projects using the following step-wise approach.²

First, FHR identified a Study Area, which is defined as the zone within which potential direct and indirect effects may possibly be discerned. Aside from providing important regional context for the projects, the Study Area sets the outer boundaries for FHR's assessment of potential direct and indirect effects. FHR concluded that a 3 kilometer-based Study Area will include the receptors of maximum modeled air concentrations and also include an area sufficient to identify individual landscape features or habitats such as wetlands and identify the potential for ecological receptors to be present.

Second, FHR established a Preliminary Action Area based on the potential direct effects of the projects. The potential direct effects from the projects include the immediate potential effects of construction and operation of the projects (e.g., ground or habitat disturbance, direct effects on listed species, intrusion of permanent structures into airspace, noise, and light). Land disturbance, lights and noise will occur within the boundary of the existing process units. Structures associated with the projects will be similar in height to existing structures. Wastewater and storm water handling systems at the refinery will accommodate the proposed projects. The #3 Crude Unit Improvements project includes an upgrade to the #3 Crude Unit desalter with a design that reduces load to the wastewater treatment plant and uses recycled water which avoids increased wastewater flow and water usage. No changes to the existing National Pollutant Discharge and Elimination System (NDPES) permit are needed. Therefore, the Preliminary Action Area was determined to be the existing operations, equipment and maintenance footprint of the refinery.

Last, FHR assessed whether any potential indirect effects within the Study Area should cause the Preliminary Action Area to be expanded to include an area of indirect effects related to air emissions, air concentration or from potential deposition of air pollutants. Table 1 provides a summary of the PSD pollutants that FHR evaluated for their potential to affect threatened and endangered species.

² This analysis has been conducted in advance of USEPA preparing a specific roadmap document for the Project. However, USEPA's roadmap documents that have been prepared for other PSD projects in Region 5 have been reviewed and taken into account in developing the scope of the analysis and in conducting the analysis.

Table 1 Summary of PSD Regulated Pollutants Evaluated for Potential Effects to Federal-Listed Threatened and Endangered Species

PSD Pollutant	Assessment Method	Results					
Particulate matter (PM ₁₀ , PM _{2.5})	Quantitative	Air dispersion modeling shows modeled air concentrations are less than significant impact levels (SILs) at or beyond the Pine Bend Refinery property boundary.					
Particulate metals	Quantitative/ qualitative	Air dispersion modeling for PM ₁₀ /PM _{2.5} shows modeled air concentrations are less than significant impact levels (SILs) at or beyond the Pine Bend Refinery property boundary. Qualitative comparison to USEPA screening levels for HAP particulate metals show emissions below screening levels.					
Volatile organic compounds	Qualitative	Because the existing facility is not a large contributor to monitored air concentrations at nearby sites, the small increase in VOC emissions associated with the proposed projects will not have an effect on ecological receptors near the facility.					
NO _X (and Ammonia (NH ₃)	Qualitative	NO _X emissions less than PSD significant emission rates with emission limits that assure an overall reduction in NO _X emissions. Potential for nitrogen deposition from ammonia emissions is de minimis. No direct effects to soil or vegetation expected.					
SO ₂ , SAM, H ₂ S, RSC	Qualitative	Because all sulfur species have estimated project emissions below the respective PSD significant emission rates, no direct effects to soil or vegetation are expected. SO ₂ emissions limits assure a decrease in SO ₂ emissions and therefore no effects expected from any potential sulfur deposition.					

SAM = sulfuric acid mist

RSC = Reduced sulfur compounds

PSD pollutants in Table 1 for which FHR did not perform an assessment include the following:

- GHGs. Local effects are not expected from these pollutants and they were not evaluated in accordance with Department of the Interior guidelines on considering GHGs in Section 7 consultations (DOI 2008).
- CO. This pollutant is typically not evaluated for potential impacts to ecological receptors.
 Because the estimated emissions for the combined projects (80 tpy) is below the PSD screening rate (100 tpy), no potential ecological impacts are expected and CO was not evaluated.

The results of quantitative air quality impact assessments show that modeled air concentration are less than significant impact levels (SILs) for PM₁₀ and PM_{2.5} at and beyond the property boundary. The results of qualitative air quality impact assessments indicate either no effects or only insignificant potential effects on natural resources. Consequently, the Preliminary Action Area was not expanded to account for air quality-related indirect effects.

FHR determined that in the absence of air quality-related indirect effects within the Study Area, the Action Area should not be expanded beyond the Preliminary Action Area. Nevertheless, for purposes of conservatism, FHR has voluntarily defined the Action Area as extending beyond the Preliminary Action Area to the property boundary of the Pine Bend Refinery.

1.4 Federally Listed Threatened and Endangered Species

There are three federally-listed species for Dakota County, according to the Minnesota Natural Heritage information System:

- Higgins-eye pearly mussel (*Lampsilis higginsii*)
- Winged mapleleaf mussel (Quadrula fragosa)
- Prairie bush clover (Lespedeza leptostachya)

Available data indicate that while these three species have been identified as threatened and endangered for Dakota County, there have been no known sightings of the listed species within the Action Area (i.e., within the facility boundary) nor within the Study Area (i.e., within 3 kilometers of the Pine Bend Refinery).

1.5 Conclusions

MPCA's action in issuing a PSD permit to FHR for the #3 Crude/Coker Improvements Permit Application at its Pine Bend Refinery in Dakota County, Minnesota will have no effect on federally listed threatened or endangered species or designated critical habitat for purposes of Section 7 of the Endangered Species Act because no federally listed threatened or endangered species, their suitable habitat, nor their designated critical habitat are within the Action Area. In addition, no federally listed threatened or endangered species, their suitable habitat, or their designated critical habitats have been identified in the Study Area. Overall, no direct or indirect effects are expected to listed species or habitat.

2.0 Introduction and Project Description

2.1 Reason for the Section 7 ESA Consultation

Flint Hills Resources (FHR) is proposing modifications to its Pine Bend Refinery located in Rosemount, Dakota County, Minnesota (Figure 1). The proposed modifications require an air permit under the Prevention of Significant Deterioration (PSD) program pursuant to the federal Clean Air Act (CAA). The Minnesota Pollution Control Agency (MPCA) has been delegated authority by EPA to issue PSD permits under the federal PSD regulations set forth at 40 C.F.R. Part 52. The action by MPCA of issuing a federal PSD permit under its delegated authority qualifies as an "agency action" that triggers the consultation requirements of the Endangered Species Act, 16 U.S.C. § 1531, et seq. (ESA).

Section 7(a)(2) of the ESA, 16 U.S.C. § 1536(a)(2), and its implementing regulations at 50 C.F.R. Part 402, requires EPA on behalf of MPCA to consult with the U.S. Fish and Wildlife Service (USFWS) or the National Marine Fisheries Service (NMFS), or both under certain circumstances, to ensure that MPCA's issuance of the PSD permit is not likely to jeopardize the continued existence of any federally listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. This Biological Evaluation (BE) provides the information necessary to support USEPA's obligations under ESA Section 7.

The following entities may participate in the ESA consultation:

- USEPA Region 5 staff
- USFWS Region 3 (Twin Cities Ecological Services Field Office) staff
- Flint Hills Resources, and Barr Engineering Company staff

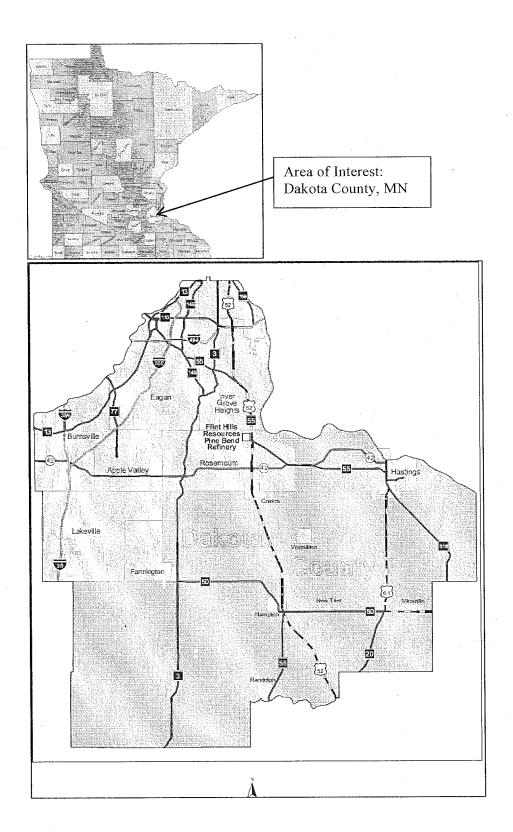


Figure 1 Approximate location of the Flint Hills Resources Pine Bend, LLC Refinery in Rosemont, Dakota County, Minnesota (Source: FHR Pine Bend, LLC)

2.2 Project Description

FHR has operated the Pine Bend Refinery since 1955. Pine Bend is a major supplier of transportation fuels and energy products to Minnesota and the Upper Midwest. These products include gasoline, diesel fuel, heating oil, jet fuel, petroleum coke, asphalt, and elemental sulfur. FHR distributes these products to customers via pipelines, trucks, barges and rail cars. The Pine Bend Refinery currently has a crude oil processing capacity of about 320,000 barrels per day. FHR Pine Bend's #3 Crude/Coker Improvements permit includes several undertakings projects that will improve the conversion of crude oil grades into transportation fuels, improve the design of heat input in the 25 Crude Unit, improve the design of heat input in the 23 Coker Unit, and eliminate steam-air decoking emissions at the coker heaters. The projects represent a significant investment in reliability improvements and equipment upgrades that will improve the emissions profile of the facility, not impact ambient air quality, improve heater efficiencies, and ensure sustained, reliable operation from turnaround to turnaround. The #3 Crude/Coker Improvements permit action covers two separate projects and one emissions reduction project.

The #3 Crude Unit Improvements Project Overview. The first project, the #3 Crude Unit Improvements Project, includes upgrades to the #3 Crude Unit and #6 Cooling Tower and/or construction of a new #7 Cooling Tower to meet the objective of continued reliable and sustained operability of the #3 Crude Unit at its current nominal capacity of 150,000 barrels per day (bpd) from crude oil feed stocks anticipated to be available in the long-term. The #3 Crude Unit Improvements project also takes advantage of existing utilization opportunities in downstream process units. As part of the #3 Crude Unit Improvements project, FHR will replace the 25 Crude Unit Charge Heater (25H1) with a new heater (new 25H2). This will result in an actual reduction of NO_X emissions through the installation of ULNB³ and SCR, and improved heater efficiency via air preheat design. Also, the #2 Crude Unit Charge Heater (11H6) will be upgraded to include SCR and air preheat design for improved heater efficiency. The #3 Crude Unit Improvements project will also result in additional equipment being placed into in volatile organic compound (VOC) service, and modifications to existing #6 Cooling Tower and/or construction of a new #7 Cooling Tower or both. The #3 Crude Unit Improvement project is described in further detail in Section 2.1 of Appendix A to the #3 Crude/Coker permit application.

 $^{^3}$ Ultra low NO_X burners referenced here achieve a NO_X performance equal to or less than 0.045 lb NO_X/MMBTU.

The #3 Coker Improvements Project Overview. The second project, the #3 Coker Improvements Project, includes replacement of two process heaters, 23H1 and 23H2, in the 23 Coker Unit with a single new process heater (new 23H3). The new heater will be designed with ULNB and SCR to reduce NO_X emissions, and will take advantage of energy efficient design. Installation of this new heater will eliminate hydrogen sulfide (H₂S) emissions that occur during infrequent, short-term (approximately 1-day per quarter) periods of heater decoking. This project is described in further detail in Section 2.2 of Appendix A to the #3 Crude/Coker permit application.

The Coker Fuel Gas Sulfur Reduction Project Overview. The third project, a #3 Coker Fuel Gas Sulfur Reduction Project, is being completed to support emissions reductions for fired heaters affected by and included within both the #3 Crude Unit Improvements Project and #3 Coker Improvements Project. The fuel gas sulfur control project will reduce SO₂ emissions at fired heaters. This project is described in further detail in Section 2.3 of Appendix A to the #3 Crude/Coker permit application.

2.2.1 Estimated Air Emissions from the Projects

FHR has evaluated these three projects to determine whether they should be aggregated for PSD regulatory purposes. EPA's policy states that separate changes, which are sufficiently related based on established criteria, should be aggregated into a single common project for the purpose of determining NSR applicability (*i.e.*, determining the project related emissions increases). The aggregation-related policy documents outline an approach that relies upon case-specific factors and the relationship between separate activities. EPA has summarized this case-by-case analysis into five criteria the agency may consider in evaluating multiple projects:

- "(1) Filing of more than one minor source or minor modification application associated with emissions increases at a single plant within a short time period.
- (2) Applications for commercial loans . . . to see if the source has treated the projects as one modification for financial purposes.

⁴ As discussed in more detail in Section 2.4.2 of Appendix A to the #3 Crude/Coker permit application, FHR is committed to reducing H₂S emissions from coker operations by 2015. The work on the 21 unit is not connected to the other projects in this permit and will proceed regardless of whether this permit is issued, even though it is being considered along with these other projects to ensure a complete NSR/PSD evaluation. Likewise, if the permit to replace the 23 unit heaters is not issued in time for FHR to start construction to meet the 2015 deadline or if the project to construct a new 23 heater does not proceed as described in Section 1.2, FHR will either proceed with a different smaller project to address H₂S emissions from the 23 unit by the 2015 deadline or request an extension of time. In the former case, FHR would proceed with a project on the existing heaters similar to the 21 unit project. Like the 21 unit work, that project would not require a permit to proceed because there is no emissions increase as a result of the physical changes.

- (3) Reports of consumer demand and projected production levels.
- (4) Statements of authorized representatives of the source regarding plans for operation. And,
- (5) EPA's own analysis of the economic realities of the projects considered together."5

Applying these criteria, the #3 Crude Unit Improvements Project and the #3 Coker Unit Improvements Project encompassed in the permit action have separate project drivers, separate funding and separate economic bases. They are technically feasible and economically viable independent of each other. Nonetheless, to eliminate any permitting uncertainty, and to add an element of conservatism to this application, FHR is voluntarily treating the #3 Crude Unit Improvement project and the #3 Coker Improvement project together as a single project for purposes of calculating emissions under the PSD air quality program at 40 C.F.R. Part 52. While the #3 Coker Fuel Gas Sulfur Reduction Project affects emission sources in both of the projects described above, that project results in a decrease in SO₂ emissions at refinery fuel gas fired sources and does not increase the emissions rate of other pollutants.

The estimated increases in emissions from the projects for PSD purposes are summarized in Table 2. As described earlier for NO_X and SO_2 , enforceable reduction projects are required by permit terms that require emission reductions that are greater than the projected increases from the permit and therefore assure no increases in actual NO_X and SO_2 emissions. It should be noted that although some of the permitted facility emissions increase slightly, the overall facility permitted emissions decrease for some of the pollutants as illustrated in Table 3.

⁵ January 22, 2003 Memorandum from John B. Rasnic, EPA to George T. Czerniak, EPA Region V titled "Applicability of New Source Review Circumvention guidance to 3M – Maplewood, Minnesota."

Table 2. Estimated PSD Emission Increases for the #3 Crude/Coker Improvements Permit

Pollutant	PSD Step 1 Emissions Increase****	PSD Significant Emission Rate	Above SER?	
	(tpy)	(tpy)	3.7	
NO_X	35.78	40	No	
SO_2	31.69	40	No	
CO .	80.06	100	No	
PM	31.35	25	Yes	
PM_{10}	29.57	15	Yes	
PM _{2.5}	28.01	10	Yes	
VOC	34.74	40	No	
SAM*	0.09	7	No	
H ₂ S/TRS**	1.14	10	No	
RSC***	2.22	10	No	
GHGs (as CO ₂ -equivalents)	419,553	75,000	Yes	

^{*} Sulfuric acid mist (SAM)

Table 3. Actual Emissions Changes Associated with the #3 Crude/Coker Improvements Projects and Comparison to Facility PTE

Scenario Description	NO _x	SO ₂	СО	PM	PM ₁₀	PM _{2.5}	VOC	GHGs (as CO ₂ e)
Existing Facility PTE (tpy)*	4,265	4,832	2,622	978	589	577	2,585	6,730,691
Total Changes (tpy)**	-31.3	-3.3	75.6	19.5	17.7	16.1	26.1	272,435
Percent of actual emissions change vs. Total facility PTE Changes without 23H3 Heater (tpy)***	-0.7%	-0.1%	2.9%	2.0%	3.0%	2.8%	1.0% 24.7	4.0%
Percent of actual emissions change vs. Total facility PTE without 23H3 Heater	-0.1%	-0.1%	2.6%	1.7%	3.3%	2.3%	1.0%	3.1%

^{*} PTE (potential to emit) from FHR's Title V Permit 009 issued January 11, 2013.

^{**} Total reduced sulfur (TRS)

^{***} RSC: Reduced Sulfur Compounds, as described in 40 CFR 60.101 and 60.641, PSD regulates H2S, carbonyl sulfide and carbon disulfide as a group referred to as "reduced sulfur compounds."

^{****} This emissions increase is for the total of all projects and would be less if the project to install a new 23H3 heater was not completed (see Attachment 1).

^{**} Reductions reflect enforceable reductions from baseline actual emissions for the PSD baseline period of 2010 - 2011. See Attachment 1 for additional details.

^{***} Identifies emissions changes if the project to install a new 23H3 heater is not completed (see Attachment 1).

2.2.2 Detailed Description of the #3 Crude Unit Improvements Project

The #3 Crude Unit, also called the 25 Unit, processes raw crude oil as it enters the refinery. In the #3 Crude Unit, the crude oil is separated or fractionated into streams that are further processed in the refinery. These streams include:

- Off gas, light hydrocarbon gases (similar to natural gas) that are further processed and used as fuel in refinery heaters and boilers;
- Light hydrocarbon liquids that are further processed into propane/butane;
- Naphthas that are further processed into gasoline;
- Fuel oils that are further processed into heating fuels, jet fuels and diesel fuel;
- Gas oils that are further processed into gasoline, jet fuels and diesel fuel; and
- Vacuum tower bottoms (VTB), an asphalt product that is either sold as asphalt or further
 processed into lighter products in the coker process units, which include gas oils, fuel oils,
 naphthas, LPG, fuel gas and petroleum coke.

The #3 Crude Unit was originally installed in 1988, and includes an atmospheric distillation unit that pre-heats, desalts and distills crude oil into fractions, a vacuum pre-fractionator and vacuum distillation unit to further distill heavy petroleum cuts, and a naphtha stabilizer unit that processes (stabilizes) naphtha feed by removing off-gases, propane, and butane.

In November 2007, FHR completed an expansion of the #3 Crude Unit to increase atmospheric distillation capacity from 100,000 barrels per day (bpd) to 150,000 barrels per day. Air Emission Permit No. 03700011-003 was issued on November 7, 2006, for the project after completion of Environmental Assessment Worksheet (EAW) review in June 2006.

Based on five years of operating history with the revamped crude unit, FHR has now identified additional modifications and reliability measures that are necessary to operate the unit at the design rate of the 2006 permit. Specifically, the intent of this proposed work is to allow for more consistent reliable operation of that unit at the 2006 permit design rate while improving the unit's ability to produce higher value petroleum fractions from the crude.

Meeting this project objective is expected to result in increased annual utilization at the #3 Crude Unit (as it is able to operate consistently closer to its design rate) as well as at certain downstream refinery process units, especially those units associated with the distillate and naphtha systems that may not otherwise operate at a higher level of utilization without this project. Accordingly, the

projects are expected to produce additional clean transportation fuels and related petroleum products as market conditions dictate.

To meet this project objective, the #3 Crude Unit will need to improve its capability to reliably and consistently "lift" more valuable light products out of heavy petroleum cuts. This capability is improved by increasing the heat input into the raw crude via re-designing and optimizing heat recovery systems (heat exchangers) as well as increasing the size of the gas-fired heater upstream of the atmospheric distillation tower. Specific to the additional fired capacity, FHR proposes to replace the existing fuel-gas fired atmospheric charge heater 25H1 (EU040) with a new heater 25H2 (EU25H2)⁶ designed to fire natural gas. The 25H2 heater will be designed with ULNB and SCR, resulting in a decrease in actual NO_X emissions compared to the 25H1 heater.⁷

Due to the expected increased use of an existing cross-over line between the #2 Crude Atmospheric Unit and the #3 Crude Vacuum Unit, two impacts are expected to occur at the #2 Crude Unit:

- The #2 Crude Vacuum Unit (16 Unit) will experience a decrease in annual utilization.
 Consequently, the 16H1 vacuum charge heater will experience decreased utilization and is not a project-affected unit.
- The #2 Crude Unit utilizes integrated heat recovery from the vacuum equipment to pre-heat feed entering the atmospheric unit. Because the 16 Unit will experience a decrease in utilization, less heat is being routed to the front of the 11-2 Unit. Therefore, the 11H6 charge heater (EU212) is expected to increase its annual firing rate to maintain outlet temperature. Since 2010, the firing of this heater has been restricted because of air draft issues that pose safety and operational concerns if the heater was to otherwise operate at elevated firing rates. This condition will now be corrected. Physical changes to the 11H6 will be completed to help accommodate this increase, and SCR is being proposed to reduce NO_X emissions at this heater. The 12H4 vacuum pre-strip heater (EU016), which operates downstream of the #2 Crude Atmospheric Distillation Unit, will not experience an increase in firing rate as a result

⁶ New emission units such as the 25H2 heater are identified in the permit application by their FHR identification number (i.e., EU25H2). As part of MPCA's permit review, the new emission units are expected to be entered into MPCA's tracking system with a unique 3-digit number, which will subsequently replace the designations made in this application.

⁷ Decreases in actual NO_X emissions are noted here for informational purposes only. They are not relied upon in a netting analysis for this permit action because the sum of emissions increases at emissions units affected by the project is less than the significant emission rate for NO_X.

of this project since it already operates at design conditions and the 11H6 changes will be designed to have sufficient capacity to increase firing to new post-project levels.

Figure 2 below generally illustrates the cross-over line between the #2 Crude Atmospheric Unit to the #3 Crude Vacuum Unit, which is increasing capacity as a result of the proposed project. As noted above, increased use of the cross-over from the #2 Crude Unit vacuum pre-flash tower to the #3 Crude Unit vacuum pre-flash tower will result in decreased utilization of the downstream 16 Unit and also require additional fired heat input at the 11H6 due to more of the heat going to the #3 Crude Vacuum Unit.

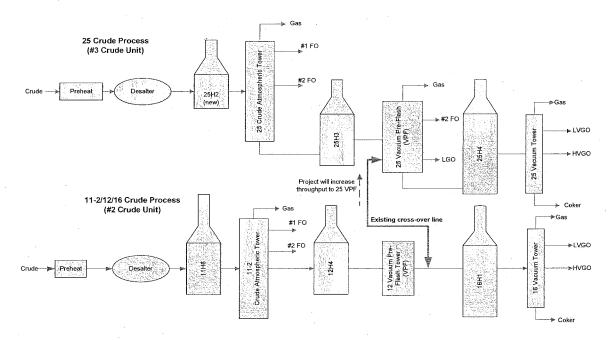


Figure 2. Process Flow Diagram of the Relationship Between the #2 Crude Atmospheric Unit and the #3 Crude Vacuum Unit at the Flint Hills Resources Pine Bend, LLC Refinery in Rosemont, Dakota County, Minnesota

FHR has evaluated the steam requirements for this project. The new steam demands from the #3 Crude Unit project include replacement of the vacuum distillation tower, which will require additional steam for stripping and for a new booster jet at the redesigned vacuum ejector system. Also, the new 25H2 heater will be designed with air pre-heat instead of steam generation for heat recovery, whereas the 25H1 heater to be shutdown is designed to generate a small amount of steam in its convection section.

The #3 Crude Unit will be designed to recover incremental heat going to the 25 Vacuum Unit in the form of a new waste heat steam generator 25E38 at the heavy vacuum gas oil (HVGO) pump around system. This excess thermal energy at the #3 Crude Unit will be used as needed to produce steam. Changes at the #3 Crude Unit will also result in additional steam production from an existing waste heat steam generator 27E120 at the downstream distillate hydrotreater.

Also, steam consumption at existing steam re-boiler 25E28 in the crude naphtha stabilizer will be reduced as a result of this project. The new waste heat steam generator 25E38, additional steam production from 27E120, and reduced steam consumption at the stabilizer re-boiler 25E28 fulfills the steam demands of both the #3 Crude Unit project described below and the #3 Coker Unit project in Section 2.4.2.

Other physical changes to the #3 Crude Unit include addition of a first-stage desalter and modifications and replacements to the atmospheric distillation tower, certain new pumps and piping, wash water systems, sewer drains, and other non-emission-unit process equipment. Equipment in VOC service at the #3 Crude Unit is covered by FS048.

This project also requires additional cooling water capacity than is currently available. FHR will modify #6 Cooling Tower, construct a new #7 Cooling Tower, or proceed with both cooling tower projects. This permit application conservatively assumes both projects will take place. The modifications to the existing #6 Cooling Tower (EU272), specifically repacking of the cooling tower (replacing internal equipment and supports), will improve thermal efficiency and slightly increase recirculation design capacity. In addition, two new cells of cross-flow configuration will be added to the cooling tower to further improve thermal efficiency of the unit. A new #7 Cooling Tower would be designed with countercurrent flow and high efficiency drift eliminators. The new permitted emissions unit associated with this project is denoted as EU#7CT.

FHR proposes to begin construction activities at the #3 Crude Unit in February 2014. FHR currently proposes to shut down the #3 Crude Unit for turnaround in fall 2015, at which point the tie-ins to new equipment (*i.e.*, 25H2 heater) will be completed. Initial start-up of the modified #3 Crude Unit will begin after completion of the fall 2015 turnaround. Changes to the 11H6 heater are proposed to also begin in February 2014 and should be completed in spring 2015. The new #7 Cooling Tower and/or changes to existing #6 Cooling Tower are proposed to begin construction in May 2014 and fall 2014, respectively, with a completion time frame of spring 2015.

In summary, the new and modified permitted emissions units associated with this project are:

- Shutdown of the existing 25H1 #3 Crude Unit Charge Heater (EU040);⁸
- Installation of a replacement 25H2 #3 Crude Unit Charge Heater (EU25H2);
- Upgrades to the 11H6 #2 Crude Unit Charge Heater (EU212);
- Additional equipment in VOC service at the #3 Crude Unit (FS048 covers all subject equipment in the process unit);
- Modifications to existing #6 Cooling Tower (EU272); and
- Construction of a new #7 Cooling Tower (EU#7CT).

2.2.3 Detailed Description #3 Coker Unit Improvements Project

The #3 Coker Unit, also called the 23 Unit, was originally installed in 1983 and is an existing two-drum delayed coking unit with an associated gas recovery unit. A process flow diagram is presented in Figure 3 below. The coker takes a low value hydrocarbon similar to asphalt and heats it to a temperature where it will crack into lighter, more valuable products leaving behind a solid coal-like substance, petroleum coke. The petroleum coke is removed from the #3 Coker Unit and sent to the Coke Loading Area for storage and distribution to customers. The lighter products of this process are separated or fractionated further and include:

- Fuel Gas, a light hydrocarbon gas similar to natural gas that is further processed and used as fuel in heaters or boilers;
- Light hydrocarbon liquids that are further processed into propane and butane;
- Naphthas that are further processed into gasoline; and
- Gas oils that are further processed into jet fuel, diesel fuel, and gasoline.

The delayed coking unit is comprised of a charge heater system, coke drum reactor vessels and associated drum deheading and condensate equipment, a cutting water system, a coker blowdown system, a compressor system, and a fractionator system to separate the feed stream into gas oils, naphtha, and gases. The gas recovery unit includes equipment to process naphtha and gas streams, including the removal of propane, butane, and fuel gas, the latter of which is routed to the 45 Unit fuel gas system.

⁸ The shutdown of equipment is described in this section as inherent to the associated project. FHR recognizes that the emissions reduction associated with shutdown of equipment may be accounted for under 40 CFR §52.21 applicability only when calculating the net emissions increase or otherwise when using the replacement unit provisions, as applicable.

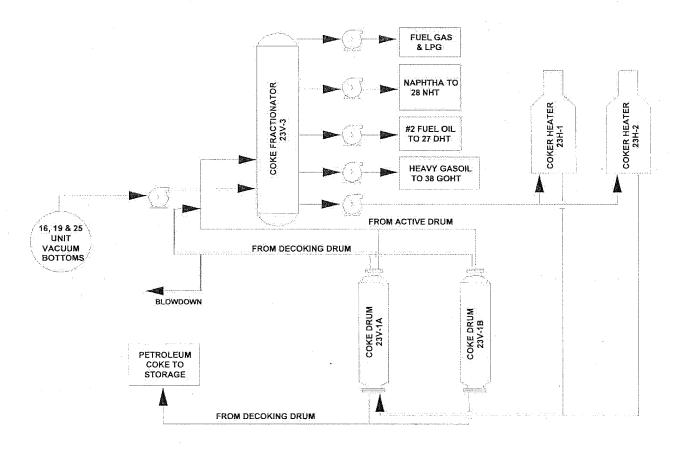


Figure 3. Process Flow Diagram for Delayed Coking Unit 23

Changes to the #3 Coker Unit are being driven, in part, to assure compliance with the Minnesota ambient air quality standards (MAAQS) for H₂S. Specifically, the two existing charge heaters 23H1 and 23H2 (EU034 and EU035) currently require steam-air decoking of the heater tubes approximately once per quarter. The intermittent activity of steam-air decoking requires the heater to be off-line, at which point a steam and air mixture is added at controlled temperatures to burn-off coke that has accumulated in the tubes over the course of operation. This activity has been identified through emissions testing as a source of H₂S and SO₂ along with other pollutants of combustion. FHR proposes to shut down these two existing charge heaters and replace them with a single new heater, 23H3 (EU23H3). The 23H3 heater will be designed for mechanical decoking, or pigging, of the heater tubes instead of steam-air decoking. Pigging involves pumping a metal-studded "pig" with water through the tubes to remove the coke scale and eliminate combustion emissions associated with the current decoking procedure. The 23H3 heater will be designed so that tube pigging can be performed while the heater is on-line and will result in the elimination of emissions associated with quarterly steam air decoking procedures. Specifically, the new heater's design will include multiple cells that can be isolated for tube pigging while the heater is on-line. Operation of the isolation valves for these cells will require a small amount of steam. As noted in Section 2.2.2, steam demand

for this project and for the #3 Crude project are fulfilled by installation of a new waste heat steam generator and reduced steam consumption at the naphtha stabilizer re-boiler in the #3 Crude Unit.

As with the 25H2 heater, the 23H3 heater will be designed with ULNB and SCR technology to achieve a reduction in NO_X emissions. The heater will also be designed for an increased outlet temperature of the coker feed as compared to the existing charge heaters. The higher outlet temperature in conjunction with other physical changes to process equipment (e.g., coke cutting jet water pump, cutting water system, and HCGO heat removal) at the #3 Coker Unit will modestly improve coke drum fill rate and coke cutting operations that should provide for increased process unit throughput on a stream-day basis.

While FHR believes that there is no increase in the hourly rate of emissions at the 23 Unit Coke Drum System (identified in this permit application as EU23Drum)⁹ associated with the improvements to the #3 Coker Unit, measurement of such emissions is difficult, and FHR will conservatively accept applicability of 40 CFR Subpart Ja at the #3 Coker Unit. Subpart Ja requires that coke drum vent gases at the E and F drums be depressured to the refinery fuel gas system to a standard of 5 pounds per square inch gauge (psig). As part of this project, FHR includes operational controls at the coke drums and related systems to comply with Subpart Ja. Further, FHR proposes to accept an annualized vent pressure limitation of 2 psig at this coke drum system upon completion of this project.

Within the gas recovery system of the #3 Coker Unit, FHR proposes to complete physical changes to improve cooling and recovery of sulfur compounds that will directly reduce the sulfur content of produced refinery fuel gas that is routed to the 45 fuel gas system (one of the two fuel gas systems in the refinery). This fuel gas sulfur reduction project, in conjunction with reducing the permitted SO₂ emissions limit on the combined fuel gas systems (GP116 – the 41 and 45 fuel gas systems) from

⁹ FHR has proposed to identify the coke drum systems as a separate emissions unit as part of the Title V permit renewal process currently underway.

atmospheric vent as a result of the change because the coke drum vent is a high-moisture and variable-flow intermittent stream, and using EPA-approved test methods has proven especially troublesome at other refineries. This issue is described by the EPA in Section 5.3.3 of the "Emissions Estimation Protocol for Petroleum Refineries" (Version 2.1.1, May 2011) as follows: "Due to the complexities of the delayed coking unit steam vent and the limited test data available, correlations to account for different process variables (venting pressure, drum temperature and steaming time prior to venting) are not currently available...". Meeting the Subpart Ja control standard to depressure each coke drum to 5 psig prior to discharging the exhaust to the atmosphere ensures that there will be no emissions increase on an annual (tons per year) basis for NSR purposes. FHR proposes to further restrict the discharge pressure to 2 psig on an annual average basis.

878 tpy to 270 tpy, will ensure that there will be no increase in SO₂ emissions from process heater fuel gas combustion as a result of these projects.

FHR proposes to begin construction activities for the new 23H3 heater and associated equipment on August 2014, with a proposed completion date in fall 2015.

FHR proposes to proceed with the proposed #3 Coker Unit Improvements Project independent of the #3 Crude Unit Improvements Project as the changes proposed at the coker unit's charge heater system are designed to eliminate H₂S emissions from steam-air decoking activities to assure compliance with the MAAQS. Nonetheless, and as noted above, FHR has considered the two projects together for determining the emissions increase under the PSD program found at 40 CFR 52.21. In summary, the new and modified permitted emissions units associated with the #3 Coker Unit Improvements Project are:

- Shutdown/Cessation of the following units/activities:
 - o 23H1 #3 Coker Heater (EU034);
 - o 23H2 #3 Coker Heater (EU035);
 - Steam/Air Heater Decoking (EU037); and
 - Steam/Air Heater Decoking (EU038);
- Installation of a replacement 23H3 #3 Coker Heater (EU23H3);
- Additional equipment in VOC service at the #3 Coker Unit (FS045 covers all subject equipment in the process unit);
- Annual emissions from the existing 23 Unit Coke Drum will decrease as a result of
 compliance with Subpart Ja of NSPS. FHR is conservatively assuming that the coke drum
 system is physically changed for the purposes of applicability under NSPS Ja for this air
 permit application. FHR is also volunteering a vent pressure annual limit of 2 psig on this
 system.

2.2.4 Detailed Description of #3 Coker Fuel Gas Sulfur Reductions Project

Within the gas recovery system of the #3 Coker Unit, FHR proposes to complete physical changes to improve cooling and recovery of sulfur compounds that will directly reduce the sulfur content of produced refinery fuel gas that is routed to the 45 fuel gas system (one of the two fuel gas systems in the refinery). This fuel gas sulfur reduction project, in conjunction with reducing the permitted SO₂ emissions limit on the combined fuel gas systems (GP116 – the 41 and 45 fuel gas systems) from 638 tpy to 270 tpy, will ensure that there will be no increase in SO₂ emissions from process heater fuel

gas combustion as a result of the #3 Crude Improvements Project and the #3 Coker Improvements Project. Since this 270 tpy fuel gas SO₂ limit is 35 tpy less than the 2010-2011 baseline actual emissions of 305 tpy, this project results in a 35 tpy decrease in actual emissions that are accounted for in Attachment 1 and Table 3. Physical changes to the coker gas recovery unit will decrease overall sulfur loading to the fuel gas system. This is being made enforceable through an annual SO₂ limit for the refinery fuel gas system (GP116).

Under the Minnesota permitting rules at Chapter 7007, this project does not require air permit approval to proceed with its start of construction because there are no emissions increases associated with it. FHR plans to begin construction activities in fall 2013 with process tie-ins to the #3 Coker Unit. Work will be completed in a time frame to comply with the lower fuel gas SO₂ emissions cap, currently scheduled for spring 2015.

3.0 ESA Methodology and Scope

3.1 Study Area and Action Area

The "action area" bounds the scope of assessing the effects of the action, (USFWS 1998 at 4-15), and so defining the "action area" is the first step in the Section 7 effects analysis process. USFWS regulations define an "action area" as "all areas to be affected directly or indirectly by the Federal action and not merely the immediate area involved in the action." (50 C.F.R. § 402.02) "Direct effects" are defined as those "direct or immediate effects of the Project on the species or its habitat," (USFWS 1998 at 4-26). "Indirect effects" are defined as those effects that "are caused by or result from the proposed action, are later in time, and are reasonably certain to occur." (*Id.* at 4-29) Further, "[i]ndirect effects may occur outside of the area directly affected by the action." (*Id.*) FHR identified the Action Area for the projects using the following step-wise approach. ¹¹

3.2 Step One: Identify the Study Area

First, FHR identified a Study Area, which is defined as the zone within which potential direct and indirect effects may possibly be discerned. Aside from providing important regional context for the projects, the Study Area sets the outer boundaries for FHR's assessment of direct and indirect effects. The Study Area for the projects was determined considering the following:

- 1. The potential for impacts from air emissions is often described as local or regional in scale. The term "local" is typically defined as being within about 10 to 100 kilometers of the emission source (USEPA 1997). For this ESA analysis, the potential for air impacts was considered to be within 10 kilometers.
- 2. For the two previous screening ecological risk analyses conducted for the Pine Bend Refinery, a 10 kilometer project area was assessed (Barr Engineering, 2007b; 2008). In both analyses the maximum modeled air concentrations occurred at the property boundary and decreased with distance from the property boundary. The maximum modeled air concentrations were used to estimate potential deposition of VOCs and particulate metals to soil, water and sediment. For both analyses, the modeled air concentrations and estimated

¹¹ This analysis has been conducted in advance of USEPA preparing a specific roadmap document for the projects. However, USEPA's roadmap documents that have been prepared for other PSD projects in Region 5 have been reviewed and taken into account in developing the scope of the analysis and in conducting the analysis.

- media concentrations at the facility property boundary and at all other locations on the modeling receptor grid were below background concentrations and levels of concern.
- 3. Initially assessing potential impacts to threatened and endangered species out to a distance of 3 kilometers from the property boundary, a potential zone of influence, is considered sufficiently inclusive based on the results of the two previous screening ecological assessments and is consistent with USEPA Region 5 staff recommendations for other ESA analyses (USEPA 2007, Recommended Scope of Analysis for Endangered Species Evaluation, Marathon Petroleum Company LLC, Detroit Heavy Oil Upgrade Project).
- 4. For the current proposed projects, PSD modeling results (PM₁₀ and PM_{2.5}) demonstrate compliance with the SILs at the property boundary, which further supports the use of a 3 km Study Area beyond the property boundary.

Considering these factors as well as the exercise of best professional judgment, the Study Area for the proposed projects is the area extending 3 kilometers (km) beyond the Pine Bend Refinery property boundary and includes an area sufficient to identify individual landscape features or habitats such as wetlands and identify the potential for ecological receptors to be present. For example, the air quality impacts assessment establishes modeling receptors across the entire Study Area for the quantitative modeling exercises. As set forth in more detail below, the analysis of potential direct and indirect impacts within the 3 km-based Study Area demonstrates that the extent of the Study Area is more than adequate to capture discernible potential direct and indirect effects.

3.3 Step Two: Identify the Action Area of Potential Direct Effects

Second, FHR established a Preliminary Action Area based on the potential direct effects of the projects. The potential direct effects from the projects include the immediate potential effects of construction and operation of the projects (e.g., ground or habitat disturbance, direct effects on listed species, intrusion of permanent structures into airspace, noise, and light).

3.3.1 Ground Disturbance and Construction Activities

The direct impacts to land (i.e., ground disturbance) from these projects does not extend outside the existing equipment, operations and maintenance footprint of the refinery and do not involve any additional land conversion activities. There is no disturbance of currently green areas. These ground disturbance and construction areas essentially identify the Preliminary Action Area for direct effects.

3.3.2 Noise

General construction activities related to the projects will occur within the existing equipment, operations and maintenance footprint of the existing facility. Processes and operations associated with the projects are similar to existing processes and operations and project-related sources (new and modified). Potential types of noise and noise levels (reported in decibels) related to the project operations will be similar to those from the existing process operations and maintenance activities.

The noise levels from the projects may be additive to the noise levels from the existing facility. However, decibel levels are on a log scale such that a small incremental increase in noise related to the projects may not change the overall decibel level of noise associated with the refinery. In addition, there will be no source of noise that moves appreciably closer to the fence line due to the projects.

Overall, the additional incremental noise from the projects is not expected to be discernible from the existing facility. Therefore, the Action Area for noise is the same area identified for construction activities that is encompassed by the existing refinery equipment, operations and maintenance activities.

3.3.3 Lighting and Visible Impacts

Lights associated with the projects will be similar to other lighting at the existing facility and are not expected to be discernible from the baseline lighting.

3.3.4 Intrusion into Air Space (Height of Structures)

All new structures associated with the project will be constructed within and amidst the existing equipment, operations and maintenance footprint of the refinery. The new structures that will be constructed will have heights that are similar to existing structures. Therefore, the Preliminary Action Area does not require expansion to address potential effects from new structure heights.

3.3.5 Water Intake and Discharge

The projects do not require an increase in allowable water appropriation (well water use).

The wastewater discharge location to the Mississippi River is approximately one-half mile to the east of the refinery processing area. Wastewater discharge will not change with the construction and operation of the project emission units. These projects replace and upgrade the #3 Crude Unit desalter unit which is a key water user and wastewater source. The desalter design increases use of recycled water rather than fresh water. The new desalter improves the settling time within the

desalter which is expected to reduce the peak loading to the wastewater treatment plant. This design enables the projects to remain approximately neutral on wastewater flow and to reduce peak wastewater treatment loads. The projects do not increase the wastewater treatment plant design capacity.

The projects do not increase storm water generation and do not expose additional soils/materials to the potential for storm water runoff.

Overall, the projects will not require additional water or increase water discharges (wastewater or storm water). As such, the Preliminary Action Area for potential direct effects does need to be expanded to include wastewater or storm water discharge locations.

3.4 Step Three: Identify the Area of Potential Indirect Effects

FHR assessed whether any potential indirect effects within the Study Area should cause the Preliminary Action Area to be expanded to include an area of indirect effects by assessing the potential for effects from modeled air concentrations of particulate.

With respect to air pollution-related effects, FHR would offer the observation that because the proposed MPCA action is the issuance of a PSD permit for GHGs, PM₁₀, and PM_{2.5}, the indirect effects of air pollution should be limited under Section 7 to the indirect effects of GHG, PM₁₀, and PM_{2.5} emissions authorized by the proposed MPCA action. FHR has included in the Biological Evaluation (BE) an analysis of the potential indirect effects of PM₁₀ and PM_{2.5}. But because the Department of the Interior has determined that impacts from GHG emissions need not be considered under Section 7 (DOI 2008), indirect effects from non-GHG emissions were not evaluated. Additionally, FHR has voluntarily included in the BE an analysis of the potential indirect effects of air pollutants other than GHGs, PM₁₀, and PM_{2.5}, including other criteria pollutants (*e.g.*, sulfur dioxide), VOCs, HAP, and nitrogen/sulfur dioxide impacts on soils and vegetation.

FHR would offer the further observation that because the net emissions increase of NO_X and SO_2 is zero (or less), the Project will result in no NO_X or SO_2 air emission-related potential indirect effects. Nevertheless, FHR has voluntarily included in the BE an analysis of the potential indirect effects of NO_X and SO_2 .

FHR evaluated the PSD pollutants in Table 1 for their potential to affect threatened and endangered species:

- Particulate (PM₁₀, PM_{2.5}) (quantitative; modeling results)
- Particulate metals (qualitative)
- VOCs (qualitative)
- NO_X (and Ammonia (NH₃)) (potential for nitrogen deposition) (qualitative)
- SO₂, SAM, H₂S, and RSC (potential for sulfur deposition) (qualitative)

PSD pollutants in Table 1 for which FHR did not perform an assessment include the following:

- GHGs. Local effects are not expected from these pollutants and they were not evaluated in accordance with Department of the Interior guidelines on considering GHGs in Section 7 consultations (DOI 2008).
- CO. This pollutant is typically not evaluated for potential impacts to ecological receptors. Because the estimate of combined project emissions (80 tpy) is below the PSD screening rate (100 tpy), no potential ecological impacts are expected and CO was not evaluated.

The results of quantitative air quality impact assessments show that modeled PM₁₀ and PM_{2.5} air concentrations at all model receptors were below significant impact levels (SILs). The results of qualitative air quality impact assessments also show only insignificant potential effects on natural resources. Consequently, the Preliminary Action Area was not expanded to account for air quality-related indirect effects. FHR determined that in the absence of air quality-related indirect effects within the Study Area, the Action Area should not be expanded beyond the Preliminary Action Area. Nevertheless, for purposes of conservatism, FHR has voluntarily defined the Action Area as extending beyond the Preliminary Action Area to the property boundary of the Pine Bend Refinery.

3.4.1 De Minimis Emission Rates

The emission inventory for the proposed projects indicates that estimated emissions increases for NO_X, SO₂, CO, VOC, H₂S/TRS, SAM and RSC are all below the respective significant emission rates (SER) for PSD permitting (Table 2). Emission estimates below the PSD SER thresholds are indicative of minimal contributions from the projects to ambient air concentrations. Because of the minimal contributions to ambient air concentrations, no impacts to listed species are expected from these pollutants from the proposed projects.

3.4.2 Emission Changes

Table 3 indicates that the projects result in an overall reduction in NO_X and SO₂ emissions and a small increase in CO, particulate and VOC emissions compared to the facility PTE. The overall net

reduction in emissions, or the small net increase in emissions, indicate there are likely no impacts to listed species from the proposed projects.

3.4.3 Modeled Criteria Pollutant Air Concentrations

Potential particulate air emissions (PM₁₀ and PM_{2.5}) associated with the proposed projects are primarily particulate from fuel gas firing from process heaters and crystallization of dissolved solids entrained in cooling tower mist. Particulate emission modeling is required for PSD air permitting. Modeled air concentrations reported in the proposed modeling protocol for this project for both PM₁₀ and PM_{2.5} were below the SIL at the property boundary. Modeled air concentrations declined with distance from the property boundary, meaning that air concentrations were well below the respective SIL at the more distant locations on the receptor grid.

Compliance with SILs at the property boundary indicates minimal contribution from the projects to ambient air concentrations. In addition, compliance with SILs at the property boundary indicates a very small zone of influence for the proposed project; no impact at the property boundary. These modeling results indicate that the projects will not have an effect on any threatened and endangered species or other potential ecological receptors in the Study Area.

3.4.4 Qualitative Assessment of Hazardous Air Pollutants

Hazardous Air Pollutants (HAPs) include both particulate metals and VOCs. Each group of HAPs is evaluated below.

3.4.4.1 Particulate Metals

Particulate emissions associated with the proposed projects are primarily from cooling towers (crystallized dissolved solids) and fuel gas combustion. Section 3.4.3 discussed the PM₁₀ modeling that was conducted and the results showing that ambient air concentrations at the property boundary are below the SIL. The SIL analysis not only demonstrates a *de minimis* impact to ground level ambient air concentrations, but by extension the SIL analysis also demonstrates insignificant impact to soils and vegetation (New Source Review Workshop Manual, Section D.II.C.). Because potential impacts from PM₁₀ are *de minimus*, particulate metal impacts are also expected to be insignificant.

In addition, estimated particulate metal emissions for the projects were compared to available USEPA (1980) screening emission rates. As shown in Table 4, all estimated emissions are below the screening emission rates (all ratios of project emissions compared to the respective screening emission rate are less than 1.0). Therefore, no adverse effects to listed species or other ecological receptors are expected from particulate metal emissions associated with the proposed projects.

Table 4. Estimated Emissions of Particulate Metals Associated with the #3 Crude/Coker Improvements Permit and Comparison to Screening Emission Rates

Pollutant	Emission Estimate (Totals for all proposed Projects) * (tons/year)	Screening Emission Rate (SER) ** (tons/year)	Ratio (Project Emissions / SER)
Arsenic	3.86E-04	2.4E-01	0.002
Beryllium	2.31E-05	5.7E-02 ***	0.0004
Cadmium	2.12E-03	3.7E-02	0.057
Chromium	2.70E-03	1.1E+00	0.002
Cobalt	1.62E-04	1.2E+00	0.0001
Manganese	7.33E-04	3.3E-01	0.002
Mercury	5.01E-04	1.5E-03 ****	0.33
Nickel	4.05E-03	6.7E+01	0.00006
Selenium	4.63E-05	1.7E+00	0.00003
Lead	3.89E-02	1.1E+01	0.0035

^{*} The emissions increase would be less if the project to install the new 23H3 heater was not completed (see Attachment 1).

^{**} Lowest screening emission rate from Table 5.7 in USEPA 1980, unless otherwise noted.

^{***} Screening emission rate for beryllium is from Table 5.6 in USEPA 1980.

^{****}Screening emission rate for mercury based on *de minimis* emission rate of 3 pounds/yr used in determining the applicability of Minnesota's Statewide Mercury Total Maximum Daily Load to proposed projects and the need to offset potential emission increases.

3.4.4.2 Volatile Organic Compounds (VOCs)

Total VOC emissions associated with the proposed projects, accounting for emissions increases and decreases, are estimated to have a small increase from existing facility emissions (Table 3). This small potential increase in VOC emissions from the refinery is considered to be negligible.

There are four monitoring locations near the Pine Bend Refinery that have measured VOC ambient air concentrations since 1992 (stations FHR420, FHR423, FHR442, and FHR443). Data for these monitoring sites are available from the MPCA. VOCs are also monitored at other locations in the Twin Cities and the state (e.g., Duluth, Minneapolis, and St. Paul). In a comparison of monitored benzene air concentrations, the MPCA (2009) identified that the Rosemount monitoring sites had concentrations similar to other locations in the Twin Cities and Duluth. This comparison indicates the refinery is not a significant contributor to ambient air concentrations at the four Rosemount monitoring sites. This is consistent with previous air evaluations that identified the refinery was a small contributor to monitored air concentrations at the Rosemount monitoring sites (Gradient 1995). Because the current refinery operations contribute very little to ambient air concentrations, a potential increase in facility emissions of 1.0% is likely not measurable. Therefore, the potential increase in VOC emissions from the projects is expected to have no effect on ecological receptors.

Potential deposition of VOCs within the Study Area is expected to be small due to the relatively small emission increase associated with the proposed projects and the fact that VOCs tend to remain in air and generally do not deposit to terrestrial or aquatic ecosystems to any great extent. Two previous modeling analyses for threatened and endangered species that included deposition estimates for VOCs have been conducted for relatively recent projects at the Pine Bend Refinery: July 2007, #3 Coker Drum Replacement Project; January 2008, #3 Crude Expansion Project. Potential VOC emissions of 1.3 and 54 tpy were estimated for the respective projects. Both modeling analyses identified very small contributions of VOCs to soil, water, and sediment. Based on the relatively small emissions increase from the currently proposed projects and the small potential deposition from VOCs, no impacts to listed species or other ecological receptors in the project area are expected.

3.4.5 Emissions of Nitrogen (NO_X and Ammonia) and Potential Effects to Soil and Vegetation

Table 2 identified that NO_X emissions for the proposed projects are below the PSD significant emission rate. Permit terms require heater shutdowns which assure that NO_X emissions will not increase as a result of the projects (Table 3) and therefore will not have any direct effects on soil or vegetation and will not increase local deposition of nitrogen.

Ammonia is not a criteria pollutant or HAP as defined in the CAA but is a pollutant of interest with regard to potential nitrogen deposition and potential emissions were estimated for the projects. If all projects proceed, which represents the highest emissions increase for ammonia, there will be approximately 20.1 tpy of ammonia emissions due to the use of selective catalytic reduction (SCR) on several stacks to reduce NO_X emissions. Most of the concern with ammonia emissions is the potential for nitrogen deposition in nearby areas because ammonia is "relatively soluble in water and may be subject to both wet and dry deposition" (Upadhyay et al., 2008).

Krupa (2003) suggests that the "most vulnerable terrestrial ecosystems (heaths, bogs, cryptogams)" would be protected at total nitrogen deposition rates of 5 to 10 kilograms nitrogen per hectare per year (kg N/(ha•yr). Hesterberg et al. (1996) suggests that unmanaged grassland should be protected at total nitrogen deposition rates below about 15 kg N/(ha•yr). A survey of grasslands in the United Kingdom showed decreasing plant species richness as total nitrogen deposition rates increased above 15 kg N/(ha•yr). The decrease in species richness was attributed to competitive displacement by a small number of nitrogen-demanding plant species (Stevens et al., 2004).

A screening estimate of potential nitrogen deposition that may be associated with the estimated ammonia emissions from the proposed projects is approximately 0.16 kg N/(ha•yr) (Table 5). Background total nitrogen deposition is estimated at 4 kg N/(ha•yr) for the Twin Cities area based on monitoring data from the Cedar Creek Natural History Area for the 2008 to 2010 time period (as measured by the National Atmospheric Deposition Network, NADP; Site MN01). The potential nitrogen deposition of 0.16 kg N/(ha•yr) that may be associated with the projects' potential ammonia emissions is about 4% of background. The potential small increase in nitrogen deposition that may be associated with the proposed projects is not significant compared to current background deposition. In addition, adding the potential incremental increase from the projects with background (4 kg/ha + $0.16 \text{ kg/ha} = \sim 4.2 \text{ kg N/(ha•yr)}$, is below the deposition thresholds of 5 to 10 kg N/(ha•yr) suggested by Krupa (2003). Therefore, no effects to nearby grasslands are expected to be associated with the potential ammonia emissions from the proposed projects.

Permit terms require heater shutdowns which assure that NO_X will not increase as a result of the projects and will not increase local deposition of nitrogen. As shown in Table 5, potential nitrogen deposition related to ammonia emissions will be below guideline values. When reductions in NO_X emissions are taken into account (Table 2), the potential deposition of nitrogen due to the projects will be less than estimated in Table 5. Overall, nitrogen emissions associated with the projects are not expected to have an impact to soil or vegetation or any ecological receptors.

Table 5. Estimated Deposition of Nitrogen from Potential Ammonia Emissions Associated with the #3 Crude/Coker Improvements Permit*

Data	Calculations or Factors	Comments
Emissions = 20.1 tpy 40,200 pounds/year 18,250,800 grams/year	2000 pounds per ton 454 grams per pound 1,000 grams = 1 kilogram (kg)	
Deposition Area: 12 km x 12 km 144 square km 144,000,000 sq. meters	1,000 meters per 1 kilometer (km) 1,000,000 sq. meters per 1 sq. km 10,000 sq. meters = 1 hectare	Deposition area of 12 km x 12 km is consistent with the Dennis et al. (2010) modeling analysis that identified that 8 to 15% of ammonia emissions from a source deposited near the emission source.
Calculation 1: All of the ammonia deposits	Annual Deposition = 18,250800 grams/yr 144,000,000 sq. meters	Very conservative assumption that all of the ammonia emitted to the air would deposit locally (within about 10 kilometers of the emission source)
	= 0.127 grams/sq. meter = 1.27 kg/ha	
Calculation 2: 15% of the ammonia deposits	Annual Deposition = 1.27 kg/ha x 0.15 = 0.19 kg/ha	Estimate that 15% of ammonia emissions deposit locally is consistent with Dennis et al. (2010).
Calculation 3: 15% of the ammonia deposits as Nitrogen (N)	Annual Deposition as N = 0.19 kg/ha x 0.82 = 0.16 kg/ha	Molecular weight of N = 14 Molecular weight of H = 1 Molecular weight of NH ₃ = 17 N = 82% of NH ₃
Background Deposition (annual)	~ 4 kg/ha	National Atmospheric Deposition Program, Site MN01 (Cedar Creek Natural History Area); average for the 2008 to 2010 time period. (http://nadp.sws.uiuc.edu/ntn/)
Background N + 15% of Project Ammonia (as N)	4 kg/ha + 0.16 = 4.16 kg/ha	Effects-level deposition:5-10 kg/ha

^{*} The nitrogen deposition is for the completion of all permit projects and would be lower if the project to install the new 23H3 heater was not completed (see Attachment 1).

3.4.6 Emissions of Sulfur (SO₂, SAM, H₂S and RSC) and Potential Effects to Soil and Vegetation

Table 2 identified that SO₂ emissions for the proposed projects are below the PSD significant emission rates. Permit terms require heater shutdowns and reduced fuel gas SO₂ emissions which assure that SO₂ will not increase as a result of the projects (Table 3) and therefore will not have any direct effects on soil or vegetation and will not increase local deposition of sulfur.

The combined project increases in SAM (0.09 tpy), H₂S (1.14 tpy) and RSC¹² (2.22) do not exceed the respective PSD SERs (Table 2). This analysis does not take into account the expected reduction in SAM from the fuel gas sulfur reduction project or the reduction in reduced sulfur compounds from coker vent improvements that, if included, would result in lower emissions than estimated here. Because these sulfur species have estimated project emissions below the respective SERs the projects are not expected to have any direct or indirect impacts to soil or vegetation or ecological receptors in general (i.e., insignificant potential for oxidation of reduced S to SO₄ and minimal potential for local deposition of sulfur).

3.4.7 Qualitative Assessment of Potential Effects from Wastewater Discharge

As previously described in section 3.3.5, the #3 Crude Unit Improvements project includes an upgrade to the #3 Crude Unit desalter with a design that reduces loading to the wastewater treatment plant and the proposed projects are not expected to increase discharge volume of wastewater or storm water. No changes to the current NPDES permit have been identified. The projects will result in continued attainment of water quality standards. Therefore, no effects to aquatic receptors are expected from the proposed projects.

3.5 Step 4. Define the Action Area

Based on the foregoing steps, FHR defines the Action Area as the area within the facility property boundary that is encompassed by the existing equipment, operations, and maintenance areas of the refinery where the projects are estimated to have potential direct effects based on ground disturbance activities and general construction. However, for conservatism, the Action Area has been delineated as the existing facility property boundary.

¹² H₂S is a subset of RSC, and therefore should not be double counted when evaluating sulfur compound increases.

Other factors that were evaluated but do not expand the Action Area include the following:

- 1) The projects do not require any additional water intake (from groundwater wells). Because there is no water intake from a river or other surface water body, water use/intake does not expand the Action Area.
- 2) The projects are expected to have a neutral effect on wastewater and storm water discharge volume. No changes to the current NPDES permit have been identified. Therefore, the storm water and wastewater discharge locations do not expand the Action Area.
- 3) The air dispersion modeling results demonstrate that PM₁₀/PM_{2.5} ambient air concentrations at the facility property boundary are less than the Significant Impact Levels (SILs). Modeling below the respective SIL at the property boundary indicates a very small area for potential direct and indirect impacts from air emissions and also supports the 3- km radius from the property boundary as the potential Study Area.

Overall, FHR determined that in the absence of air quality- and water quality-related indirect effects, the Action Area should not be expanded beyond the Preliminary Action Area that was identified for potential direct effects.

4.0 Description of Federally Listed Species

There are three federally-listed species for Dakota County, Minnesota:

- Higgins-eye pearly mussel (Lampsilis higginsii)
- Winged mapleleaf mussel (Quadrula fragosa)
- Prairie bush clover (*Lespedeza leptostachya*)

None of these federally listed threatened or endangered species, their suitable habitat, or their designated critical habitat are within either the Action Area. No critical habitat has been identified in the Study Area. It is highly unlikely that the listed species or their suitable habitat are present in the Study Area.

4.1 Higgins-eye Pearly Mussel

The Higgins eye pearly mussel (*Lampsilis higginsii*) occurs in the Mississippi River north of Lock and Dam 19 at Keokuk, Iowa and between Illinois and Iowa. The mussel has also been identified to be potentially present naturally in the Mississippi River near Hastings, Minnesota, several miles downstream from the Pine Bend Refinery. Currently, the lower St. Croix River between Taylors Falls, Minnesota and Prescott, Wisconsin has the largest known populations of the mussel throughout its known range (Minnesota DNR, www.dnr.state.mn.us/rsg/profile.html; accessed Dec. 4, 2012).

As of 2004, the USFWS reintroduced the species to Pool 3 in the upper Mississippi River (this stretch of river includes the Hastings, MN area) (USFWS, 2004). In 2000-2001, a survey of the Mississippi National River and Recreation Area, a 72 mile stretch of river from Hastings northward to approximately Ramsey and that encompassed the portion of the river near the Pine Bend refinery, did not identify the presence of the Higgins eye pearly mussel (USFWS website: www.nps.gov/miss/naturescience/musssurvey.htm; accessed on Dec. 4, 2012).

Essential habitat areas identified by the USFWS include portions of the St. Croix River from Franconia, Wisconsin down to Prescott, Wisconsin, the Mississippi River at Lansing, Iowa, near Harper's Ferry Iowa, Prairie du Chien, Wisconsin, near Guttenberg, Iowa, Cordova, Illinois, and Moline, Illinois (USFWS, 2008). The mussel favors "stable" sand and gravel that is not "fine" such as silt or "coarse" such as "cobble". They avoid sand that is "unstable" or "shifting", "packed clay," "flocculent silt," "organic material," and "concrete". They have been noticed to live where there are few plants in the river, but have been observed where plants are on the shore. Not much is known

about the impacts of organic compounds on the mussels. Water quality parameters identified to potentially effect *L. higginsii* include un-ionized ammonia, select metals, and possibly some organic compounds (USFWS, 2004).

Because many inorganic and organic contaminants that enter aquatic systems associate with fine sediments (*i.e.*, silts and clays), the greatest likelihood for adverse effects for these contaminants should be depositional areas with fine sediments. The existing data for *L. higginsii*, however, suggests that the species is not generally found in areas with a relatively significant amount of sediment deposition. Thus *L. higginsii* are generally not located in areas where concentrations of organic compounds are likely to reach toxic levels (USFWS, 2004).

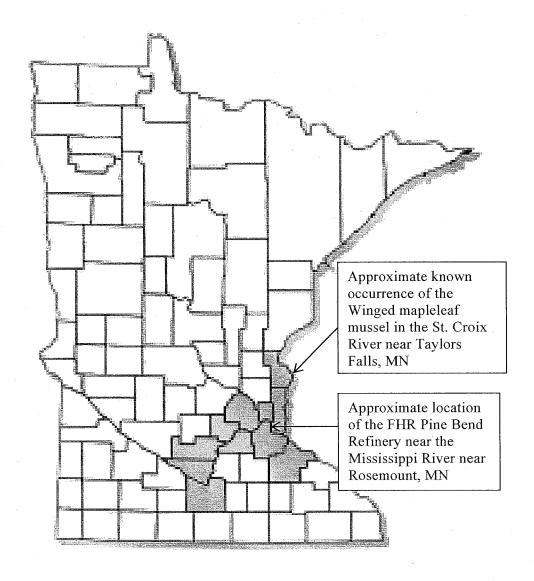
4.2 Winged Mapleleaf Mussel

According to the Minnesota DNR, surveys in the St. Croix River indicate that Winged mapleleaf mussel (*Quadrula fragosa*) is restricted to a 20 km (12 mi.) stretch south of Taylors Falls, Minnesota, over clean gravel, sand, and rubble substrates and in clear areas of high water quality. It is "only found under conditions that would be considered high quality for mussel habitat" (MDNR, 2012).

Its habitat is described as follows:

Historically, the winged mapleleaf has been described as a large river species. It has been found in the St. Croix River in riffles dominated by gravel, sand, and rubble substrates in water averaging about 1 m (3 ft.) deep. In general, winged mapleleafs have similar habitat requirements as the other mussel species residing in the St. Croix River mussel community. Three species of mussels, the deertoe (Truncilla truncata), the fawnsfoot (T. donaciformis), and the monkeyface (Quadrula metanevra), have been found to be significantly associated with winged mapleleafs (MDNR, 2012).

Figure 4 shows the extent of potential habitat for the Winged mapleleaf mussel in Minnesota and the approximate location of FHR Pine Bend refinery in relation to the known occurrence of the mussel. The estimated distance from Taylors Falls to the Pine Bend Refinery by water is approximately 45 miles (75 kilometers). Figure 5 identifies the 3 kilometer project area, including the portions of the Mississippi River near the Pine Bend Refinery. The project area is more than 10 kilometers from the St. Croix River. Given the distance from the project area to the St. Croix River the proposed project is not likely to have any effect on the Winged mapleleaf mussel.



(adapted from information on the Minnesota Dept. of Natural Resources website: http://www.dnr.state.mn.us/rsg/profile.html?action=elementDetail&selectedElement=IMBIV39050#)

Figure 4 Extent of Potential Habitat for the Winged Mapleleaf Mussel and its Known Occurrence in the St. Croix River near Taylors Falls, Minnesota.

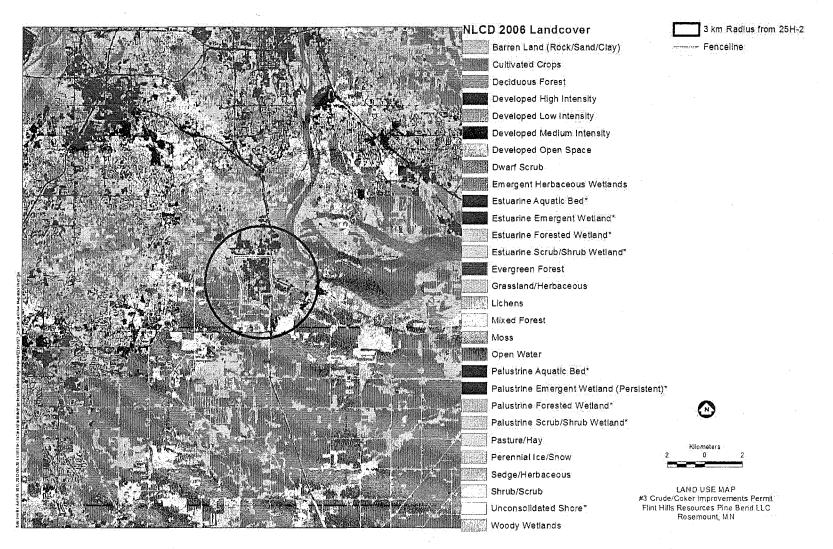
4.3 Prairie Bush Clover

Prairie bush clover (*Lespedeza leptostachya*) is a Midwestern endemic found at less than 100 sites within the tall grass prairie region of just four states: Illinois, Minnesota, Wisconsin, and Iowa. Most of the large populations are found near the Des Moines River Valley in southwest Minnesota and the lakes region in northwestern Iowa. Prairie bush clover favors mesic moderately damp to dry prairie. The plant's rarity mostly has to do with loss of prairie habitat to settlement. Much of the existing population survived because its location was too steep or rocky to plow by settlers.

While dry prairie habitat is present east of Highway 52, the 2004 MDNR sensitive species survey conducted for the FHR Pine Bend Refinery did not identify prairie bush clover in the surveyed area (within 3 kilometers of the refinery), and the surveyed habitat is more shaded than the plant's preference. It is unlikely that the prairie bush clover is present within the project area or that the proposed project poses any threat to it.

The presence/absence of mussels in the Mississippi River was not included in the 2004 MDNR sensitive species survey.

Figure 5 shows the land cover within 10 kilometers of the Pine Bend Refinery, as well as the project area (area within 3 kilometers of the projects; demarked by a black circle). It can be seen that much of the land surrounding the site is developed and there is low likelihood of the presence of prairie bush clover.



(Note: the black circle identifies the 3 kilometer radius around the facility; i.e., the project area)

Figure 5. Land Cover and Land Use Around the Flint Hills Resources Pine Bend, LLC Refinery in Rosemount, Dakota County, Minnesota

5.0 Effects of the Permitting Action

5.1 Air Quality

Table 2 identifies that the projects will result in emissions of NO_X, SO₂, CO, VOCs and other sulfur species (H₂S, SAM, RSC) that are less than the PSD SERs. PSD SER thresholds are indicative of minimal contributions from the project to ambient air concentrations.

Table 3 identifies the projects result in an overall net reduction of NO_X and SO₂ emissions, and small increases for CO, particulate (PM/PM₁₀/PM_{2.5}) and VOCs, when compared to existing facility PTE emissions. The emission decreases indicate no contributions of NO_X and SO₂ from the projects to ambient air concentrations. The small increases in emissions for CO, particulate and VOCs are not expected to have any effects on ambient air concentrations. Additionally, the PM₁₀/PM_{2.5} air dispersion modeling results indicate air concentrations are below the respective SILs at the property boundary and in the larger Study Area. Because of the minimal contributions to ambient air concentrations, it is expected there would be minimal contributions to local deposition as well.

Table 4 indicates that particulate metal emissions estimated for the projects are below screening effects level rates. This indicates no effects expected from particulate metal emissions.

Table 3 indicates there is an overall net reduction in NO_X emissions from the facility. Table 5 indicates that potential nitrogen deposition related to ammonia emissions will be small and will be below significant levels. In addition, there is an overall net reduction in SO_2 emissions from the facility. Therefore, no effects to soils or vegetation are expected as there would be no change or a potentially small reduction in local deposition of nitrogen and sulfur.

Based on the air quality analyses conducted, it is concluded that the projects' air emissions will have no effects on any federally-listed species or other ecological receptors that may be present in the Action Area or the Study Area.

5.2 Water Quantity and Water Quality

Water for the projects will be supplied by the current facility's groundwater wells and no changes in water appropriations are expected due to the projects.

The projects are not expected to increase wastewater and storm water discharge volume. No changes have been identified for the current NPDES permit.

Overall, the wastewater and storm water associated with the projects is expected to have no physical effects at discharge locations and no effect on water quality. Therefore, no effects are expected to occur to federally-listed species or ecological receptors in the Action Area or within the Study Area.

5.3 Noise

The projects are within an active industrial area that is subject to routine construction, operations and maintenance activities. Project-related construction activities will be managed to reduce noise impacts including proper construction equipment maintenance and fitting equipment with standard noise reducing equipment. The additional noise associated with the construction and then operations of the projects is not expected to be discernible from the noise associated with the existing facility.

In addition, considering the industrial nature of the Action Area and background noise levels associated with the current facility, federally-listed species are not present. Therefore, the potential incremental increase in noise levels associated with the construction and operation of the projects will have no effect on any species.

5.4 Infrastructure-Related Impacts

No new infrastructure independent of the new equipment identified in the projects' description is required to support the projects. Therefore, there are no infrastructure-related impacts to consider for the projects and a determination of "no effect" to federally-listed species (or other ecological receptors) is made for the Action Area and Study Area.

5.5 Human Activity Impacts

Minor temporary increases in human activity compared to the existing operation of the refinery will result from the projects during the construction and possibly during the operation phases. Additional temporary workers may be needed for the construction phase of the projects with some additional employees hired to handle the work related to the additional process operations. However, the existing facility and projects are within a zoned industrial area and that is also part of the Highway 55 transportation corridor and adjacent to the Mississippi River and associated barge shipping channel. As a result of the industrial nature of the area and existing human activity related to the area's general construction, operations and maintenance activities, the temporary incremental increase of construction-related activity and the smaller incremental activity from long-term employees is expected to have no effect on the Action Area or the Study Area.

5.6 Species Effect Analysis

No direct effects are expected to mussel species as they cannot be present in the Action Area. Because the Action Area encompasses an industrial area and the project-related construction will be within the existing equipment, operations, and maintenance footprint of the existing facility, the prairie bush clover is not expected to be present. No effects to listed species are expected in the Action Area.

No critical habitat has been identified in the Study Area. It is highly unlikely for a federal listed species to be present in the Study Area. Because the direct effects from the projects are limited to the existing equipment, operations and maintenance footprint of the facility, emission estimates are below PSD significance levels and/or air dispersion modeling indicates air concentrations are below significance levels at the property boundary and beyond, no direct or indirect effects to listed species are expected in the Study Area.

MPCA's action in issuing a PSD permit to FHR for the #3 Crude/Coker Improvements Project at its Pine Bend Refinery in Dakota County, Minnesota will have no effect on federally listed threatened or endangered species or designated critical habitat for purposes of Section 7 of the Endangered Species Act because no federally listed threatened or endangered species, their suitable habitat, nor their designated critical habitat are within the Action Area. In addition, no federally listed threatened or endangered species, their suitable habitat, or their designated critical habitats have been identified in the Study Area.

Overall, no direct or indirect effects are expected to listed species or habitat.

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Attachment 1

ESA Emission Calculation Table

Emission Summary for #3 Crude/Coker Improvements Permitting Scenarios

Change Descrip tion	Emission Unit/Fugitive Source Description	MPCA EU/FS ID	Notes	NOx tpy	SO2 tpy	CO tpy	PM tpy	PM10	PM2.5	VOC tpy	GHG tpy CO2e
Juits	New 25H2 – #3 Crude Unit Charge Heater	(EU25H2)	[1]	10.85	0.94	14.28	10.71	10.71	10.71	7.70	167,066
Zew I	New VOC Equipment at #3 Crude Unit	FS048	[1],[2]	-	_	-	-	-	-	2.60	55
Increases from New Units	New 23H3 – #3 Coker Unit Charge Heater	(EU23H3)	[1]	11.00	0.76	11.56	8.67	8.67	8.67	5.78	135,795
creases	New VOC Equipment at #3 Coker Unit	FS045	[1],[2]	-	-	-	_	-		2.16	45
<u> </u>	New #7 Cooling Tower	(EU#7CT)	[1]	-	-	-	1.53	0.72	0.003	7.36	_
from ed Jnits	#3 Coker Unit Coke Drum System	(EU23DRUM)	[1]	-	•-	-	-	-	-		-
Increases from Changed Existing Units	#6 Cooling Tower	EU272	[1]	-	-	-	1.81	0.85	0.004	0.92	-
Inc	11H6 – #2 Crude Unit Charge Heater	EU212	[1]	-	GP116	8.90	4.48	4.48	4.48	3.24	68,085
lated	25H4 – #3 Crude Unit Vacuum Heater	EU324	[1],[3]	6.15	GP116	1.62	1.21	1.21	1.21	0.87	18,679
ct-re	27H102 – 27 DHT Charge Heater	EU051	[1],[3]	2.11	GP116	0.05	0.10	0.10	0.10	0.07	6,254
Proje ⁄ities	31H7 – #5 HDS Charge Heater (Naphtha)	EU058	[1],[3]	0.28	GP116	0.46	0.04	0.04	0.04	0.03	650
Increases from Non-modified Project-related Existing Units/Activities	32H5,6,7 – Powerformer Reactor Heaters	EU073,074,075	[1],[3]	1.92	GP116	0.05	0.38	0.38	0.38	0.27	5,837
Non-m ing Uni	37H1 – 37 NHT Charge Heater	EU093	[1],[3]	0.39	GP116	-	0.09	0.09	0.09	0.06	1,860
from Existi	37H2 – 37 NHT Stripper Reboiler	EU094	[1],[3]	0.42	GP116	0.31	0.12	0.12	0.12	0.09	2,008
eases	38H1A – 38 GOHT A-Train Heater	EU102	[1],[3]	1.11	GP116	0.91	0.07	0.07	0.07	0.05	1,284
Incr	38H1B – 38 GOHT B-Train Heater	EU103	[1],[3]	0.75	GP116	0.61	0.05	0.05	0.05	0.04	864

Change Descrip tion	Emission Unit/Fugitive Source Description	MPCA EU/FS ID	Notes	NOx tpy	SO2	CO tpy	PM tpy	PM10 tpy	PM2.5	VOC tpy	GHG tpy CO2e
,1,	38H2 – 38 GOHT Fractionation Charge										
ect	Heater	EU104	[1],[3]	0.26	GP116	0.08	0.20	0.20	0.20	0.14	3,974
Pro	31H4 – HDS Heater (Hot Oil System)	EU056	[1],[3]	0.55	GP116	0.02	0.14	0.14	0.14	0.10	2,126
Increases from Non-modified Project-related Existing Units/Activities	Sulfur Recovery Units	GP112	[1]	_	28.90	41.19	1.76	1.76	1.76	-	4,971
on-m Inits/	Sulfur Degassing System (Storage and Loading)	GP115	[1]	-		-	-			-	
om Noting U	Liquid Petroleum Storage and Transport	GP009	[1]	-	-	_	-	•		3.25	-
ases fr	Petroleum Coke Storage and Transport	FS009	[1]	_	_	-	-	_	_		_
Incre	31H2 – #2 HDS Fractionation Heater (Merox off-gas)	EU055	[1]	_	1.09	-	-		_	_	-
uo	25H1 – #3 Crude Unit Charge Heater Shutdown	EU040	[3], [4]	(18.84)	GP116	(0.08)	(5.93)	(5.93)	(5.93)	(4.29)	(74,936)
Emissi	23H1 – #3 Coker Unit Heater Shutdown	EU034,037	[3], [4]	(21.13)	GP116	(3.70)	(3.03)	(3.03)	(3.03)	(2.19)	(38,525)
Enforceable Emission Reductions	23H2 – #3 Coker Unit Heater Shutdown	EU035,038	[3], [4]	(17.14)	GP116	(0.71)	(2.93)	(2.93)	(2.93)	(2.12)	(33,657)
orc	Fuel Gas System for SO ₂ Emissions via										
Enf	#3 Coker Gas Recovery Unit	GP116	[5]	-	(35.00)	-	-	-	-	-	
	11H6 NOx Limit Reduction via SCR	EU212	[6]	(10.00)	-	-	-	_	-	-	••
		Total			(3.30)	75.57	19.47	17.69	16.13	26.14	272,435
	Total without 23H3 Heater				(4.06)	68.42	16.75	14.98	13.41	24.67	208,822

Notes:

- [1] Emission increase representation directly from PSD emission summary; MPCA application dated 11/16/12, Appendix A Table 3-4. Values may change pending upcoming permit supplement.
- [2] Only the resulting additional equipment associated with this project is considered in the PSD analysis.
- [3] SO2 emissions from these heaters are covered by the fuel gas emissions limit for which the SO2 PTE restriction is being reduced see GP116.
- [4] Reductions reflect baseline actual emissions from the PSD baseline period of 2010 2011.
- [5] Emission decrease accounts for an enforceable SO2 limit of 270 tpy which is 35 tpy less than the 2010-2011 baseline emissions of 305 tpy. A netting analysis was not performed so this emission reduction was not considered in the PSD analysis.
- [6] FHR is proposing to accept a 16.5 tpy NOx limit for 11H6 which is 10 tpy below the 2010-2011 baseline emissions of 26.5 tpy. A netting analysis was not performed so this emission reduction was not considered in the PSD analysis.



Pine Bend Refinery

ENVIRONMENTAL DEPARTMENT

P.O. Box 64596 Saint Paul, Minnesota 55164-0596 651.437.0700

May 7, 2013

Ms. Jennifer Darrow US EPA Region 5 77 West Jackson Boulevard Mail Code: AR-18J Chicago, IL 60604-3507

RE:

Flint Hills Resources Pine Bend, LLC

Endangered Species Act Biological Evaluation and Cultural Resources Assessment in Support of the #3 Crude/Coker Improvements Permit Application

Dear Ms. Darrow:

As discussed, please find the attached updated emission tables for the informal Endangered Species Act-(ESA) consultation originally submitted on January 25, 2013 and for the Cultural Resources Assessment (CRA) originally submitted March 14, 2013 in support of the #3 Crude/Coker Improvements Permit Application submitted to the Minnesota Pollution Control Agency (MPCA) on November 16, 2012.

The above referenced permit application was revised on April 30, 2013 in order to adopt a more accurate calculation methodology for greenhouse gases (GHG). The resultant overall GHG emissions for the project under New Source Review changed from 419,553 tons per year of CO₂e in the original application to 420,664 tons per year CO₂e due to this change in calculation methodology. This small increase resulting from the change in GHG emission calculation methodology revised the GHG values in the tables in the ESA and CRA reports but does not affect the conclusions of the ESA or CRA. Table 2 of the ESA and CRA, Table 3 of the ESA and CRA, and Attachment 1 of the ESA included GHG emission values and are attached with revised GHG emissions.

The HAP emission data originally provided per your request via electronic mail on April 19, 2013 for the ESA review is attached to this signed cover letter as well. This includes Table 4 of the ESA with a corrected lead value and a Supplemental HAP table that also provided project related non-metal HAPs as requested.

If you have any questions about this submittal, please contact me at michael.sinclair@fhr.com (651) 437-0625.

Sincerely,

Mike Sinclair

Senior Air Permitting Engineer

Flint Hills Resources Pine Bend Refinery

Encl.

cc: Ms. Rachel Rineheart, USEPA Mr. Tarik Hanafy, MPCA

Revised ESA and CRA Table 2 (May 7, 2013 GHG Revision):

Table 2. Estimated PSD Emission Increases for the #3 Crude/Coker Improvements Permit

Pollutant	PSD Step 1 Emissions Increase**** (tpy)	PSD Significant Emission Rate (tpy)	Above SER?	
NO _x	35.78	40	No	
SO_2	31.69	40	No	
CO	80.06	100	No	
PM	31.35	25	Yes	
PM ₁₀	29.57	15	Yes	
PM _{2.5}	28.01	10	Yes	
VOC	34.74	40	No	
SAM*	0.09	7	No	
H ₂ S/TRS**	1.14	10	No	
RSC***	2.22	10	No	
GHGs (as CO ₂ -equivalents)	420,664	75,000	Yes	

^{*} Sulfuric acid mist (SAM)

Revised ESA and CRA Table 3 (May 7, 2013 GHG Revision):

Table 3. Actual Emissions Changes Associated with the #3 Crude/Coker Improvements Projects and Comparison to Facility PTE

·								GHGs (as
Scenario Description	NO _x	SO ₂	CO	PM	PM_{10}	PM _{2.5}	VOC	CO ₂ e)
Existing Facility PTE (tpy)*	4,265	4,832	2,622	978	589	577	2,585	6,730,691
Total Changes (tpy)**	-31.3	-3.3	75.6	19.5	17.7	16.1	26.1	259,103
Percent of actual emissions								
change vs. Total facility PTE	-0.7%	-0.1%	2.9%	2.0%	3.0%	2.8%	1.0%	3.8%
Changes without 23H3								
Heater (tpy)***	-4.1	-4.1	68.4	16.7	15.0	13.4	24.7	203,566
Percent of actual emissions		,						
change vs. Total facility PTE							•	
without 23H3 Heater	-0.1%	-0.1%	2.6%	1.7%	3.3%	2.3%	1.0%	3.0%

^{*} PTE (potential to emit) from FHR's Title V Permit 009 issued January 11, 2013.

^{**} Total reduced sulfur (TRS)

^{***} RSC: Reduced Sulfur Compounds, as described in 40 CFR 60.101 and 60.641, PSD regulates H2S, carbonyl sulfide and carbon disulfide as a group referred to as "reduced sulfur compounds."

^{****} This emissions increase is for the total of all projects and would be less if the project to install a new 23H3 heater was not completed (see Attachment 1).

^{**} Reductions reflect enforceable reductions from baseline actual emissions for the PSD baseline period of 2010 - 2011. See Attachment 1 for additional details.

^{***} Identifies emissions changes if the project to install a new 23H3 heater is not completed (see Attachment 1).

Revised ESA Table 4 (May 7, 2013 Revision incorporating April 19, 2013 corrected Pb value):

Table 4. Estimated Emissions of Particulate Metals Associated with the #3 Crude/Coker Improvements Permit and Comparison to Screening Emission Rates

Pollutant	Emission Estimate (Totals for all proposed Projects) * (tons/year)	Screening Emission Rate (SER) ** (tons/year)	Ratio (Project Emissions / SER)
Arsenic	3.86E-04	2.4E-01	0.002
Beryllium	2.31E-05	5.7E-02 ***	0.0004
Cadmium	2.12E-03	3.7E-02	0.057
Chromium	2.70E-03	1.1E+00	0.002
Cobalt	1.62E-04	1.2E+00	0.0001
Manganese	7.33E-04	3.3E-01	0.002
Mercury	5.01E-04	1.5E-03 ****	0.33
Nickel	4.05E-03	6.7E+01	0.00006
Selenium	4.63E-05	1.7E+00	0.00003
Lead	9.64E-04	1.1E+01	0.0035

^{*} The emissions increase would be less if the project to install the new 23H3 heater was not completed (see Attachment 1).

^{**} Lowest screening emission rate from Table 5.7 in USEPA 1980, unless otherwise noted.

^{***} Screening emission rate for beryllium is from Table 5.6 in USEPA 1980.

^{****}Screening emission rate for mercury based on *de minimis* emission rate of 3 pounds/yr used in determining the applicability of Minnesota's Statewide Mercury Total Maximum Daily Load to proposed projects and the need to offset potential emission increases.

Revised ESA Attachment 1 (May 7, 2013 GHG Revision):

Emission Summary for #3 Crude/Coker Improvements Permitting Scenarios

Change Descrip tion	Emission Unit/Fugitive Source Description	MPCA EU/FS ID	Notes	NOx tpy	SO2	CO tpy	PM tpy	PM10 tpy	PM2.5	VOC	GHG tpy CO2e
Units	New 25H2 – #3 Crude Unit Charge Heater	(EU25H2)	[1]	10.85	0.94	14.28	10.71	10.71	10.71	7.70	167,066
Vew	New VOC Equipment at #3 Crude Unit	FS048	[1],[2]	-	-	-		_	<u>-</u>	2.60	55
Increases from New Units	New 23H3 – #3 Coker Unit Charge Heater	(EU23H3)	[1]	11.00	0.76	11.56	8.67	8.67	8.67	5.78	135,795
rease	New VOC Equipment at #3 Coker Unit	FS045	[1],[2]		-	-	_	-	-	2.16	45
lnc	New #7 Cooling Tower	(EU#7CT)	[1]	-		·	1.53	0.72	0.003	7.36	_
from d Inits	#3 Coker Unit Coke Drum System	(EU23DRUM)	[1]	-	-	-		_		-	_
Increases from Changed Existing Units	#6 Cooling Tower	EU272	[1]	-	, -	_	1.81	0.85	0.004	0.92	
Incr	11H6 – #2 Crude Unit Charge Heater	EU212	[1]	-	GP116	8.90	4.48	4.48	4.48	3.24	72,067
ated	25H4 – #3 Crude Unit Vacuum Heater	EU324	[1],[3]	6.15	GP116	1.62	1.21	1.21	1.21	0.87	17,755
ect-rel	27H102 – 27 DHT Charge Heater	EU051	[1],[3]	2.11	GP116	0.05	0.10	0.10	0.10	0.07	5,945
l Proje vities	31H7 – #5 HDS Charge Heater (Naphtha)	EU058	[1],[3]	0.28	GP116	0.46	0.04	0.04	0.04	0.03	689
Increases from Non-modified Project-related Existing Units/Activities	32H5,6,7 – Powerformer Reactor Heaters	EU073,074,075	[1],[3]	1.92	GP116	0.05	0.38	0.38	0.38	0.27	6,182
don-m	37H1 – 37 NHT Charge Heater	EU093	[1],[3]	0.39	GP116		0.09	0.09	0.09	0.06	1,323
from N Existi	37H2 – 37 NHT Stripper Reboiler	EU094	[1],[3]	0.42	GP116	0.31	0.12	0.12	0.12	0.09	1,765
eases	38H1A – 38 GOHT A-Train Heater	EU102	[1],[3]	1.11	GP116	0.91	0.07	0.07	0.07	0.05	1,070
Incr	38H1B – 38 GOHT B-Train Heater	EU103	[1],[3]	0.75	GP116	0.61	0.05	0.05	0.05	0.04	797

Change Descrip tion	Emission Unit/Fugitive Source Description	MPCA EU/FS ID	Notes	NOx tpy	SO2 tpy	CO-	PM tpy	PM10	PM2.5 tpy	VOC tpy	GHG tpy CO2e
ect-	38H2 – 38 GOHT Fractionation Charge Heater	EU104	[1],[3]	0.26	GP116	0.08	0.20	0.20	0.20	0.14	2,888
d Proje	31H4 – HDS Heater (Hot Oil System)	EU056	[1],[3]	0.55	GP116	0.02	0.14	0.14	0.14	0.10	2,253
odifiec	Sulfur Recovery Units	GP112	[1]	-	28.90	41.19	1.76	1.76	1.76		4,971
on-mo Jnits//	Sulfur Degassing System (Storage and Loading)	GP115	[1]	_	_	_	-	_	_	-	-
Increases from Non-modified Project- related Existing Units/Activities	Liquid Petroleum Storage and Transport	GP009	[1]	-	<u>-</u> .	-	-		-	3.25	_
	Petroleum Coke Storage and Transport	FS009	[1]	-	-	-	 -	-	_	-	
Incre	31H2 – #2 HDS Fractionation Heater (Merox off-gas)	EU055	[1]	_	1.09	_	-	-	-	-	-
uo	25H1 – #3 Crude Unit Charge Heater Shutdown	EU040	[3], [4]	(18.84)	GP116	(0.08)	(5.93)	(5.93)	(5.93)	(4.29)	(81,305)
Emission	23H1 – #3 Coker Unit Heater Shutdown	EU034,037	[3], [4]	(21.13)	GP116	(3.70)	(3.03)	(3.03)	(3.03)	(2.19)	(43,376)
ceable Emi	23H2 – #3 Coker Unit Heater Shutdown	EU035,038	[3], [4]	(17.14)	GP116	(0.71)	(2.93)	(2.93)	(2.93)	(2.12)	(36,882)
Enforceable Reducti	Fuel Gas System for SO ₂ Emissions via #3 Coker Gas Recovery Unit	GP116	[5]	_	(35.00)		_	-		-	-
	11H6 NOx Limit Reduction via SCR	EU212	[6]	(10.00)			-		-	_	-
	Total			(31.33)	(3.30)	75.57	19.47	17.69	16.13	26.14	259,103
Total without 23H3 Heater				(4.06)	(4.06)	68.42	16.75	14.98	13.41	24.67	203,566

Notes:

- [1] Emission increase representation directly from PSD emission summary; MPCA application dated 11/16/12, Appendix A Table 3-4 or from April 30, 2013 GHG permit supplement.
- [2] Only the resulting additional equipment associated with this project is considered in the PSD analysis.
- [3] SO2 emissions from these heaters are covered by the fuel gas emissions limit for which the SO2 PTE restriction is being reduced see GP116.
- [4] Reductions reflect baseline actual emissions from the PSD baseline period of 2010 2011.
- [5] Emission decrease accounts for an enforceable SO2 limit of 270 tpy which is 35 tpy less than the 2010-2011 baseline emissions of 305 tpy. A netting analysis was not performed so this emission reduction was not considered in the PSD analysis.
- [6] FHR is proposing to accept a 16.5 tpy NOx limit for 11H6 which is 10 tpy below the 2010-2011 baseline emissions of 26.5 tpy. A netting analysis was not performed so this emission reduction was not considered in the PSD analysis.

439-96-5)	0.0007	0.33	0.002	3.07	0.02%	Gas combustion emissions from tall h
9 7-6)	0.0005	0.0015	0.33	0.64	0.08%	Gas combustion emissions from tall h
-0)	0.004	67.00	0.00006	35.79	0.01%	Gas combustion emissions from tall h
49-2)	0.00005	1.70	0.00003	0.01	0.76%	Gas combustion emissions from tall h
) [4]	0.001	11.00	0.0001	0.11	0.89%	Gas combustion emissions from tall h

reflect enforceable reductions from baseline actual emissions for the PSD baseline period of 2010 - 2011.

nental Protection Agency (U.S. EPA). 1980. A screening procedure for the impacts of air pollution sources on plants, soils, and animals (Fig. 1980.

netal HAPs are less than screening thresholds.

sion value is a correction of the value provided in Table 4 of Flint Hills Resources January 2013 ESA submittal. Facility total updated to incorpor irce.

nic and Non-Metal Inorganic HAP Emissions Totals and Comparison to Total Facility Emissions

Pollutant .	Project Emissions (tpy) [1]	Facility Total PTE Emissions (tpy)	Project Increase (%)	Primary Project Source of HAP Emissic
e (25321-22-6, all				Gas combustion emissions from tall heater stacks
para- isomer)	0.002	0.04	6.51%	
50-00-0)	0.1	19.04	0.76%	Gas combustion emissions from tall heater stacks
-3)	4.4	122.45	3.59%	Gas combustion emissions from tall heater stacks
5-07-0)	0.0003	5.29	0.01%	Gas and process gas combustion emissions from tall heat
· (75-15-0) [2]	0.3	7.30	3.70%	Gas and process gas combustion emissions from tall heat
(463-58-1) [2]	0.8	21.90	3.70%	Gas and process gas combustion emissions from tall heat
unds (Not Na or K)	0.00002	15.09	0.00%	Gas and process gas combustion emissions from tall heat
50-5)	0.0003	0.02	1.11%	Cooling Tower / Water Treatment Additive
thane (79-00-5)	0.0003	0.04	0.79%	Refinery sector fugitive sources: equipment, cooling towe
.06-99-0)	0.000003	0.0004	0.79%	Refinery sector fugitive sources: equipment, cooling towe
entane (540-84-1)	0.01	1.34	0.60%	Refinery sector fugitive sources: equipment, cooling towe
-2)	0.3	186.12	0.18%	Refinery sector fugitive sources: equipment, cooling towe
-4)	0.001	0.61	0.17%	Refinery sector fugitive sources: equipment, cooling towe
(108-90-7)	0.0003	0.05	0.64%	Refinery sector fugitive sources: equipment, cooling towe
8)	0.0002	0.03	0.79%	Refinery sector fugitive sources: equipment, cooling towe
L00-41-4)	0.1	25.89	0.29%	Refinery sector fugitive sources: equipment, cooling towe
nide (106-93-4)	0.00004	0.005	0.79%	Refinery sector fugitive sources: equipment, cooling towe
ide (107-06-2)	0.0004	0.05	0.79%	Refinery sector fugitive sources: equipment, cooling towe
L-20-3)	0.05	68.14	0.07%	Refinery sector fugitive sources: equipment, cooling towe
2)	0.01	2.53	0.43%	Refinery sector fugitive sources: equipment, cooling towe
ic Matter (POM)	0.03	15.15	0.22%	Refinery sector fugitive sources: equipment, cooling towe
1-3)	0.4	169.24	0.22%	Refinery sector fugitive sources: equipment, cooling towe
0-7)	0.4	192.76	0.21%	Refinery sector fugitive sources: equipment, cooling towe

Is reflect enforceable reductions from baseline actual emissions for the PSD baseline period of 2010 - 2011. Organic HAP re ecreases that are permit requirements were not quantified.

lemissions updated to reflect change in calculation methodology based on Refinery ICR Protocol, consistent with NSR project

Emissions Summary Table

Proje nt Emissic (tpy	ons Emissions of All	% Increase of Project Metals HAPs /	HAP increase Ranges by Primary !
		0.3% average increase in project metal	0.004 – 6.5% for individual HAPs prim
		HAPs	process gas combustion with ta